PE
12-31-01

INC.

2001 ANNUAL REPORT

GeoResources, Inc. is a natural resources company engaged in three principal business segments – oil and gas exploration, development and production; oil and gas drilling; and leonardite mining and the manufacture of leonardite-based products. GeoResources, Inc. is traded on the Nasdaq SmallCap Market under the symbol "GEOI."

GeoResources has a substantial oil and gas exploration and production operation in the Williston Basin. This business segment historically constitutes more than 70 percent of GeoResources' revenue and earnings. In 2001, the Company produced an average of 416 net equivalent barrels of oil per day from 134 productive wells located within 50 fields in North Dakota and Montana. At December 31, 2001 GeoResources owned proved reserves of 2.2 million barrels of oil equivalent with an SEC value of $7 million. Ninety-seven percent of those reserves are crude oil.

Due to the shortage of working drilling rigs in some portions of the Williston Basin, in late 2001 GeoResources elected to form a subsidiary company, Western Star Drilling Company, and acquire a drilling rig for its own use and for contract drilling operations. In September 2001 GeoResources purchased a drilling rig capable of drilling to 8,000 feet. After retrofitting was completed, the rig was deployed in the north central region of North Dakota.

In addition to its oil and gas activities, the Company operates a leonardite mine and processing plant at Williston, North Dakota. At the Williston facility a distinctive type of oxidized lignite coal called leonardite is mined from leased reserves and processed into several different specialty products. Those products include drilling mud additives for use in the oil and natural gas drilling industry and applications in metal working factories and in agriculture.

THE YEAR AT A GLANCE

(financial highlights in $000s except per share data)	2001	2000	1999	1998	1997
For the Year					
Oil and Gas Revenues	$ 3,064	$ 4,436	$ 2,689	$ 1,662	$ 3,425
Leonardite Revenues	914	676	652	719	765
Total	$ 3,978	$ 5,112	$ 3,341	$ 2,381	$ 4,190
Net Income (Loss)	$ 42	$ 1,415	$ 482	$ (1,605)	$ 766
Per Share	$ .01	$ .36	$ .12	$ (.39)	$ .19
At Year End					
Working Capital (Deficit)	$ (224)	$ 424	$ 639	$ 112	$ 18
Total Assets	$ 8,202	$ 7,450	$ 7,329	$ 6,705	$ 8,032
Long-Term Debt	$ 1,035	$ 375	$ 1,610	$ 1,625	$ 666
Current Maturities	$ 125	$ 125	$ 175	$ 316	$ 457
Stockholders' Equity	$ 5,536	$ 5,713	$ 4,462	$ 4,052	$ 5,692
Production Statistics					
Productive Wells (gross)	134	134	134	134	120
Oil (bbls)	149,916	165,156	182,356	173,102	211,266
Gas (mcf)	11,496	10,139	8,042	8,491	10,408
Leonardite (tons)	9,779	7,696	7,736	7,772	8,094
Proved Reserves At Year End					
Oil (bbls)	2,098,000	2,487,000	2,566,000	1,286,000	2,387,000
Gas (mcf)	350,000	545,000	257,000	234,000	253,000

TO OUR SHAREHOLDERS *APRIL 12, 2002*

Once again it is a pleasure to report to you our progress for 2001, my 20th year of doing so. Last year was another tumultuous one for oil prices which fluctuated from a high of $30 per barrel early in the year, to the $20 per barrel range immediately after the tragedy of September 11th. Our operations, relatively undisturbed by oil prices, were dramatically impacted by shortages of oilfield equipment and services. Particularly in our core area of operations, the East Flank of the Williston Basin, a shortage of drilling rigs hampered our drilling program. This led to our greatest operational decision in 2001, the decision to purchase our own drilling rig.

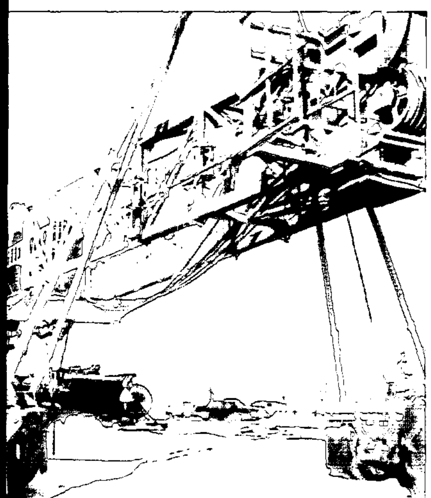
A little background to this situation might be of interest to some. Over the last few years, oil industry consolidation has reduced the number of vendors providing supplies and services in most segments of the industry. In the U. S. portion of the Williston Basin, an area of some 75,000 square miles, there were only three drilling contractors operating in 2001. And of those three, only one had a rig dedicated to drilling shallower wells of less than 8,000 feet. In addition, this drilling contractor has a corporate relationship with another operator who is a competitor of ours in exploration and production activities. These factors and our belief that drilling rigs could be entering a period of generally higher utilization and demand led to our decision to create Western Star Drilling Company to provide drilling services for our own account and to third parties.

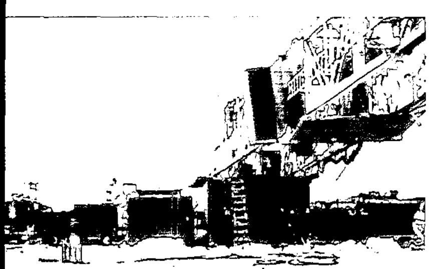
On the following pages you will find a montage of pictures from our rig, Western Star Drilling Company Rig E25. We have also included graphical presentations of our operational and financial performance during the year and the Securities and Exchange Commission Form 10-KSB detailing our progress. At the time of this writing, we have completed drilling two new wells where we own 100% working interest. And we have permitted three others, also 100% working interest. Subject to spring breakup conditions, we expect Rig E25 to begin a "washdown" re-entry of an existing wellbore in the Landa Field of Bottineau County within the next few weeks, and we anticipate several other projects in the coming months. Our longer-range goal over the next few years is unitization of three more fields for the purpose of secondary recovery by waterflood. All of these unitizations will require drilling; therefore Rig E25 is a critical part of our plan. There are several other areas of the Williston Basin that need shallow hole drilling services, but our best case scenario is to keep the rig drilling in north central North Dakota. We believe the rig is worth every bit of the $1,000,000 we have invested in it and that it could be sold or deployed in other areas very easily. But its real value to GeoResources is the capacity it gives us to pursue our drilling and development program in our core area of operations.

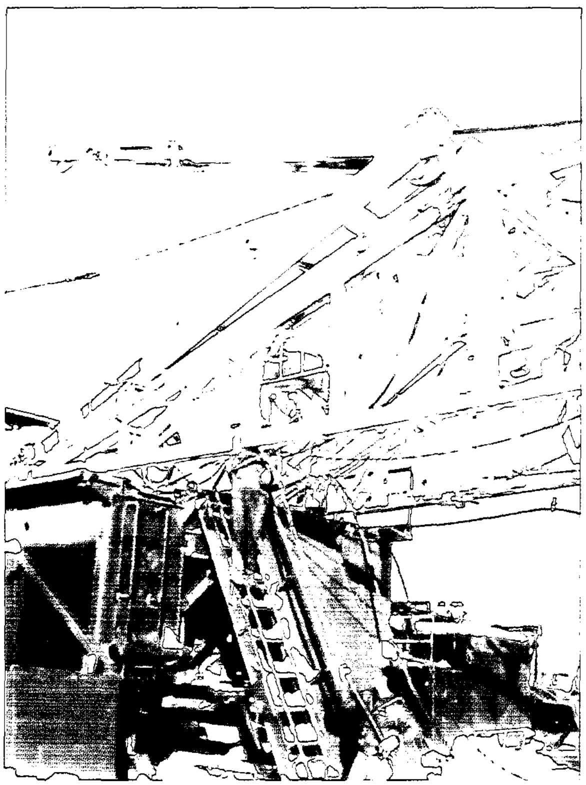
With 2002 we have seen some improvement in oil prices, and we have remained busy building the company's assets. We are not delighted with the market valuation given most small oil and gas companies on NASDAQ, but we continue to investigate ways to maximize shareholder value. And we believe that in the current political climate domestic energy supplies are more important than ever. On behalf of the Board of Directors and all of us employed by GeoResources, we wish to thank you for your confidence and support. Personally I hope we can make 2002 GeoResources' "Year of the Bit". Domestic oil and gas is important to our country, and we are committed to doing our part to sustain a domestic energy industry.

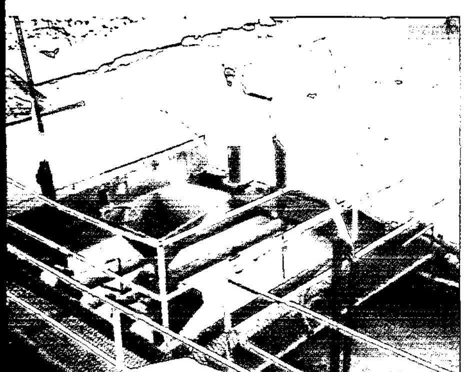
J.P. (Jeff) Vickers
President

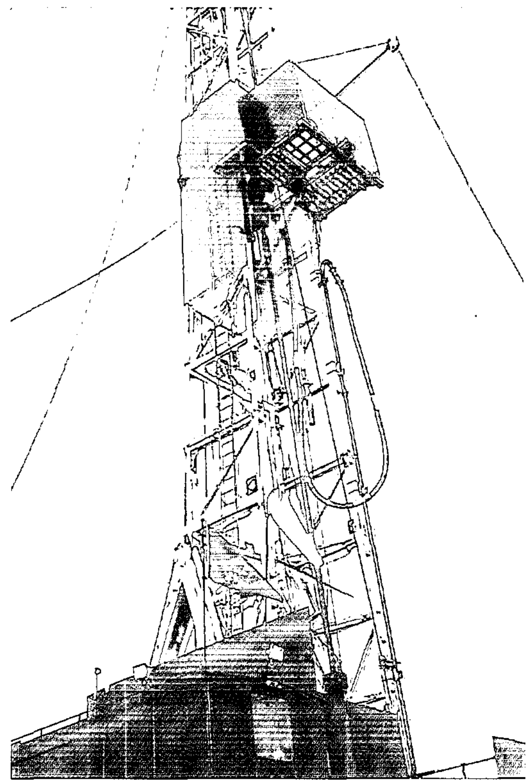
Western Star
Drilling Company







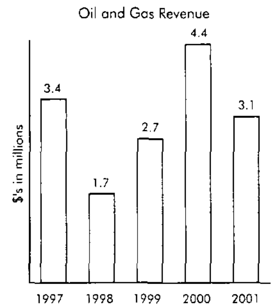




Pictured on these pages is Rig E25 during rebuilding by Steven's Welding of Glenburn, North Dakota and during actual drilling operations in the Williston Basin. The rig is a state-of-the-art "little double," designed for shallow drilling with a 102-foot, 350,000-pound mast and a 250,000-pound draw-works. The rig features a large, spacious, well lighted dog house that houses the drilling instrumentation and tools. And the rig's safety features include a flush mounted "racking board" on the drilling floor. Several features of Rig E25, including a 14-foot substructure, make it suitable for drilling vertical wells of less than 8,000 feet, for drilling horizontal wells with similar true vertical depths and for under-balanced horizontal drilling.

Western Star Drilling Company gives GeoResources rig accessibility to actively pursue drilling objectives while at the same time providing possible revenue from other operators' projects. It also gives the Company more control in the timing of projects and makes us more self sufficient in drilling operations.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS



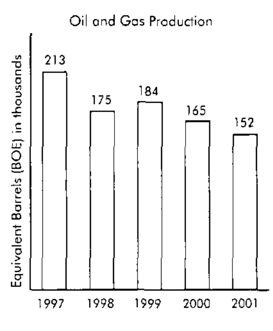
INTRODUCTION

We operate through three primary segments: 1) oil and gas exploration and production; 2) oil and gas drilling; and 3) leonardite mining and processing. Our major leonardite products are oil and gas drilling mud additives.

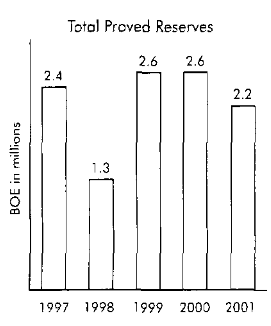
RESULTS OF OPERATIONS

Comparison of 2001 to 2000 Revenue and Gross Margin

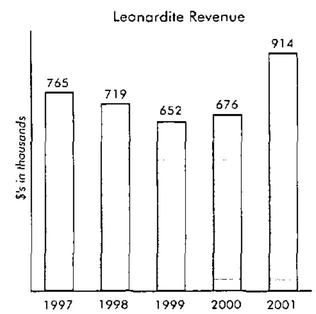
Oil and gas sales were $3,064,000 in 2001 compared to $4,436,000 in 2000, a decrease of $1,372,000 or 31%. This decline in revenue was largely due to a 24% decrease in the average value we received for our oil production during 2001. The 2001 average oil price per barrel was $20.25 compared to an average of $26.75 in 2000 and $14.70 in 1999. Occasionally, we consider the use of various New York Mercantile Exchange (NYMEX) financial instruments to hedge against the risks of oil price declines. The volume of oil and gas sold in 2001 decreased 15,000 barrels of oil equivalent (BOE) or 9% to 152,000 BOE from 167,000 BOE in 2000. The lower 2001 production volumes sold principally followed the approximate average production decline of our wells, as a lack of rig availability and other oilfield supplies and services severely hampered our drilling plans. For example, we entered into a contract to drill a well in mid-August 2001 with the only contractor available to us. Due entirely to that contractor's schedule, the well was not drilled until mid-January 2002, some five months later. This was unacceptable to us and led to our decision to get involved with drilling operations as discussed below.



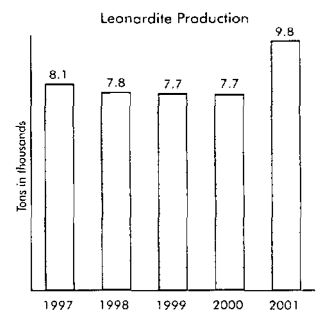
Oil and gas production costs in 2001 were $1,856,000 compared to $1,659,000 in 2000, an increase of $197,000 or 12%. These higher costs were due to two primary factors, an increase of $101,000 in repairs and maintenance costs that were incurred to make discretionary improvements to existing facilities during this period of higher cash flow, and generally higher costs of petroleum-related supplies and services including, for example, propane, electricity, treating chemicals and contract labor. Production costs expressed on a per equivalent barrel basis increased $2.29 per BOE or 23% to average $12.23 for 2001 compared to $9.94 for 2000. The increase in per barrel costs occurred as we produced more of our marginal (higher cost per barrel) wells in the oil price environment existing in the first three quarters of 2001 and performed workovers in lieu of drilling to try to maintain production. Our gross margin for 2001 oil and gas operations without deductions for depletion and selling, general and administrative (SG&A) expenses, decreased to $1,208,000 or 39% of revenue compared to $2,777,000 or 63% of revenue for the year 2000.



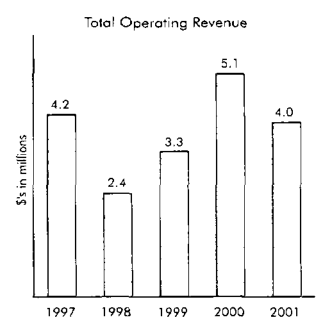
During 2000 and 2001, most operators gained confidence in sustained higher energy prices that existed prior to September 11, 2001, and consequently demand for oilfield supplies and services, particularly drilling services, increased substantially. This put a strain on available resources which were already in tight supply from years of reduced activity. In north central North Dakota, the only remaining drilling contractor with a rig dedicated to the area has a corporate relationship with another operator that is a private oil and gas company that is a competitor of ours in exploration and production and acquisition activities. This fact and the unavailability of timely drilling services encouraged us to become involved in drilling operations. In September 2001, we decided to fund the acquisition and retrofitting of a drilling rig to meet our future drilling needs as well as that of other operators in the core areas of our operations, principally the Williston Basin East Flank. No actual drilling operations were commenced in 2001, but all rig rebuilding was completed and the rig spudded its first well for us on January 2, 2002. This rig is held in a North Dakota private company named Western Star Drilling Company ("WSDC") that at this time is a wholly-owned subsidiary of GeoResources, Inc.



Leonardite product sales were $914,000 in 2001 compared to $676,000 in 2000, an increase of $238,000 or 35%. This increase was due to a combination of several factors, the main one being the increased activity of drilling in the Gulf of Mexico. Another factor was a 6% increase in average price per ton for leonardite sold in 2001 resulting from a slightly higher demand for our specialty products, which have higher selling prices and an increase in our base price for leonardite. Production sold in 2001 was 9,779 tons at an average price of $93.42 compared to 7,696 tons at an average price of $87.83 for 2000.



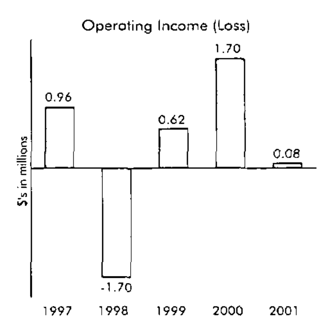
Cost of leonardite sold was $824,000 in 2001 compared to $669,000 in 2000, an increase of $155,000 or 23%. Average production costs per ton were $84.29 and $86.91 for 2001 and 2000, respectively. Costs per ton decreased approximately 3% for 2001 compared to 2000 due mainly to increased production which spread fixed costs over a larger volume.



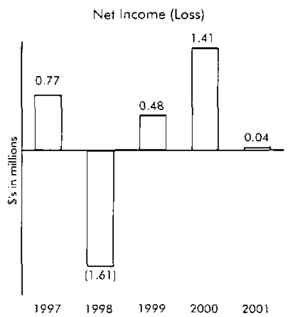
Gross margin for 2001 leonardite operations before deductions for depreciation and selling, general and administrative expenses was $89,000 or 10% of revenue compared to $7,000 or 1% of revenue for 2000. The increase in 2001 gross margin was primarily the result of the higher price per ton discussed above.

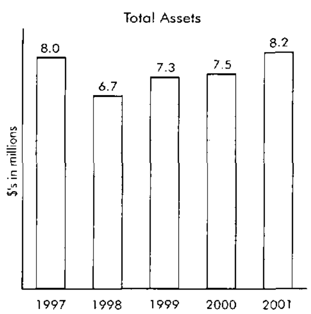
Comparison of 2001 to 2000 Consolidated Analysis

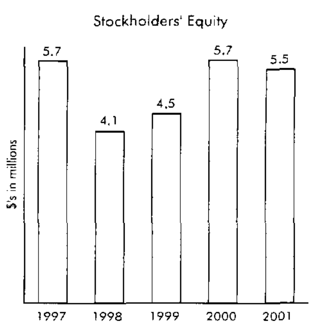
Total revenue for 2001 decreased $1,134,000 or 22% to $3,978,000 from $5,112,000 in 2000. This decrease was due to the lower average oil price and the 9% lower oil production in 2001 compared to 2000.

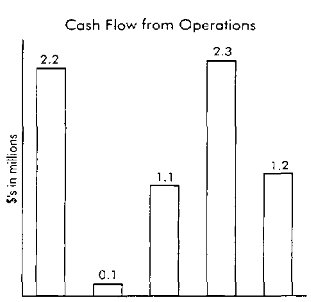


Total operating costs for 2001 increased by $489,000 or 14% to $3,897,000 compared to $3,408,000 in 2000. This increase in total costs resulted from increases in oil and gas production costs and costs of leonardite sold, as previously discussed, coupled with smaller increases in the other expense categories. Depreciation, depletion and amortization expense in 2001 was $745,000 or









10% higher than 2000, due to reserve values and volumes being evaluated at substantially lower prices at year end 2001 compared to year end 2000. Selling, general and administrative costs (SG&A) were $66,000 or 16% higher in 2001 compared to 2000 due to an increase in our level of operations in 2001, and the addition of one administrative employee.

Lower 2001 total revenue and higher total operating costs resulted in operating income of $81,000 for 2001 compared to income of $1,704,000 in 2000. Nonoperating expenses declined from $97,000 in 2000 to $2,000 in 2001, due to lower interest expense. Income before taxes in 2001 was $79,000 compared to income of $1,608,000 in 2000.

Provisions for income tax expense in 2001 was $37,000 compared to $193,000 in 2000. The amount for each year is primarily reflective of changes in our tax-deferred assets and liabilities under the provisions of SFAS No. 109.

As a result of all the factors discussed above, net income for 2001 was $42,000 or $0.01 per share compared to a net income of $1,415,000 or $0.36 per share in 2000.

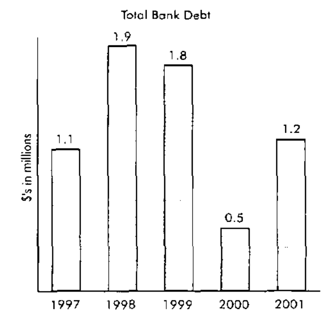
LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2001, we had current assets of $1,063,000 compared to current liabilities of $1,286,000 for a current ratio of .83 to 1 and working capital deficit of $224,000. This compares to a current ratio of 1.39 to 1 at December 31, 2000, and working capital of $424,000.

During the year ended December 31, 2001, we generated cash flows from operating activities of $1,192,000, which was $1,112,000 less than the amount generated during 2000. This decrease was essentially due to lower oil prices and production discussed previously. We anticipate that cash flows from operations and funds available under our $3,000,000 revolving line of credit ("RLOC") will be sufficient to meet our short-term cash requirements. The RLOC, which had an available balance of $2,225,000 at December 31, 2001, allows borrowing until January 5, 2004, with repayment due by January 5, 2008.

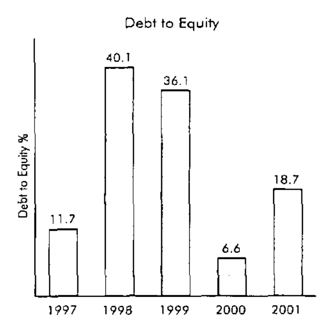
During 2001, our investing activities used $1,844,000 of cash for additions to property, plant and equipment. Approximately $968,000 of these additions was made to purchase and retrofit a drilling rig. In addition, $544,000 of capitalized costs was used to set up a centralized production facility in our South Starbuck Madison Unit, a secondary recovery unit in Bottineau County, North Dakota; a re-entry project in Stark County, North Dakota, and to pay our share of completion costs on a Red River well in Montana where we own an 8% working interest. Portions of the remaining $332,000 used in investing activities consisted of $24,000 for miscellaneous office and leonardite plant expenditures, $135,000 for unproved oil and gas property costs and $31,000 for proved property acquisition costs.

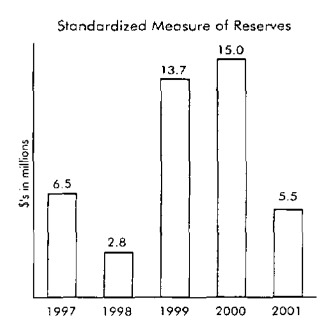
During 2001, our financing activities consisted of $115,000 of cash utilized for regularly scheduled principal payments under long-term debt agreements, and we used an additional $220,000 of cash to purchase our common stock on the open market. During the second half of 2001, we borrowed $775,000 on our RLOC to finance the purchase and retrofitting of our drilling rig.



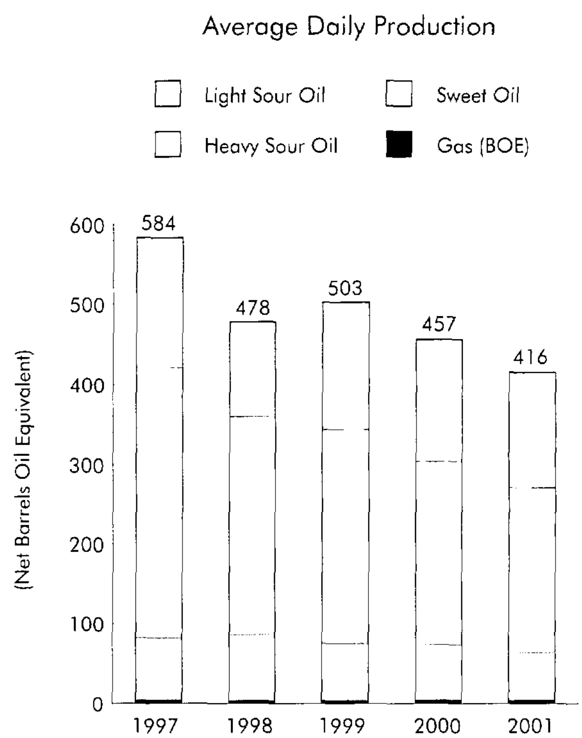
We estimate that our development costs for 2002 relating to our proved developed nonproducing and proved undeveloped oil and gas properties will be approximately $1,050,000. Planned expenditures for 2002 also include delay rentals and other exploration costs of approximately $100,000. Capital expected to be used for 2002 principal payments required under existing debt agreements is $125,000.

We expect to continue to evaluate possible future purchases of additional producing oil and gas properties and the further development of our properties. We believe our long-term cash requirements for such investing activities and the repayment of long-term debt can be met by future cash flows from operations and, if necessary, possible forward sales of oil reserves or additional debt or equity financing.





ANNUAL OIL & GAS INFORMATION



	2001	2000	1999
Quantities Sold			
Oil (net Bbls)	149,916	165,156	182,356
Gas (net Mcf)	11,496	10,139	8,042
Total (net BOE)	151,832	166,846	183,696
Average Sales Price			
Oil (per Bbl)	$ 20.75	$ 26.75	$ 14.70
Gas (per Mcf)	$ 2.40	$ 1.80	$ 1.10
Average Production Cost Per BOE	$ 12.23	$ 9.94	$ 6.61

	2001		2000	
	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)
Proved Developed				
Producing	1,316	71	1,652	76
Nonproducing	14	279	28	469
Proved Undeveloped	767	--	807	--
Total Proved Reserves	2,097	350	2,487	545
Total Proved Reserves (MBOE)	2,155		2,578	
Future Cash Flow from Proved Reserves (M$)	$ 11,715		$ 35,856	
Future Cash Flow Discounted at 10% (M$)	$ 6,687		$ 21,002	
Standardized Measure of Discounted Future Net Cash Flows (M$)	$ 5,480		$ 15,022	

Productive Wells*

	Oil		Gas	
Year	Gross	Net	Gross	Net
2001	108	80.13	26	25.25
2000	108	80.12	26	25.75
1999	110	80.04	24	24.00
1998	110	77.78	24	24.00
1997	96	67.78	24	24.00

	Producing Wells				Service Wells	
	Oil		Gas			
Year	Gross	Net	Gross	Net	Gross	Net
2001	108	80.14	0	0.00	15	12.41
2000	107	80.05	0	0.00	15	12.41
1999	107	78.99	0	0.00	15	12.39
1998	75	53.19	0	0.00	14	11.41
1997	94	66.80	0	0.00	14	11.41

*Producing wells and nonproducing wells deemed capable of production.

U. S. SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-KSB

(Mark One)

[X] Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2001.

[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from ____________________ to ____________________.

Commission File Number - 0-8041

GEORESOURCES, INC.

Colorado
(State or other jurisdiction of incorporation or organization)

84-0505444
(I.R.S. Employer Identification No.)

1407 West Dakota Parkway, Suite 1-B
Williston, North Dakota
(Address of Principal executive offices)

58801
(Zip Code)

(Issuer's telephone number including area code) ....(701) 572-2020

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act: Common Stock, par value $0.01

Check whether the Issuer (1) filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 12 months (or for such shorter period that the Issuer was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Check if there is no disclosure of delinquent filers in response to Item 405 of Regulation S-B is not contained in this form, and no disclosure will be contained, to the best of registrant's knowledge in definitive proxy or information statements incorporated by reference in Part III of this Form 10-KSB or any amendment to this Form 10-KSB. [X]

Issuer's revenues for its most recent fiscal year. $3,977,703

The aggregate market value of the voting and non-voting common equity computed by reference to the price at which the common equity was sold, or the average bid and ask price of such common equity held by nonaffiliates as of March 1, 2002, was approximately $4,823,015.

Shares of $0.01 par value Common Stock outstanding at March 1, 2002: 3,787,477

Documents Incorporated By Reference - None

PART I.

ITEM 1. BUSINESS

General Development of Business

GeoResources, Inc. is a natural resources company engaged in three principal business segments: 1) oil and gas exploration, development and production; 2) oil and gas drilling; and 3) mining of leonardite (oxidized lignite coal) and manufacturing of leonardite based products which are sold primarily as oil and gas drilling mud additives. We were incorporated under Colorado law in 1958 and were originally engaged in uranium mining. We built our first leonardite processing plant in 1964 in Williston, North Dakota, and began participating in oil and gas exploration and production in 1969. In 1982, we completed construction of a larger leonardite processing plant in Williston that is in use today. Financial information about our three operating segments is presented in Note B to the Financial Statements in Item 8 of this report.

Information contained in this Form 10-KSB contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 which can be identified by the use of words such as "may," "will," "expect," "anticipate," "estimate" or "continue," or variations of these words or comparable terminology. In addition, all statements other than statements of historical facts that address activities, events or developments that we expect, believe or anticipate will or may occur in the future, and other such matters, are forward-looking statements.

Our future results may vary materially from those anticipated by management and may be affected by various trends and factors which are beyond our control. These risks include the competitive environment in which we operate; changing oil and gas prices; the demand for oil, gas and leonardite; availability of drilling rigs; dependence upon key management personnel and other risks described in this report.

Oil and Gas Exploration, Development and Production

Our oil and gas exploration and production efforts are concentrated on oil properties in the North Dakota and Montana portions of the Williston Basin. We typically generate prospects for our own exploitation, but when a prospect is believed to have substantial risk or cost, we may attempt to raise all or a portion of the funds necessary for exploration or development through farmouts, joint ventures, or other similar types of cost-sharing arrangements. The amount of interest retained by us in a cost-sharing arrangement varies widely and depends upon many factors, including the exploratory costs and the risks involved.

In addition to originating our own prospects, we occasionally participate in exploratory and development prospects originated by other individuals and companies. We also evaluate interests in various proved properties to acquire for further operation and/or development.

As of December 31, 2001, we had developed oil and gas leases covering approximately 14,600 net acres in Montana and North Dakota, and during 2001 sold an average 416 net equivalent barrels of oil per day from 134 gross (105 net) productive wells located primarily in North Dakota.

We sell our crude oil to purchasers with facilities located near our wells. Our gas reserves are also contracted to purchasers in the area near our wells.

Oil and Gas Drilling

Due to a shortage of working drilling rigs we believe exists in some portions of the Williston Basin area, we elected to form a subsidiary company to own and operate a rig for our own use and for contract drilling operations. In September 2001, we purchased a drilling rig capable of drilling to 8,000 feet. After retrofitting, the rig was deployed in the north central region of North Dakota. From time to time, the rig will be used to drill our prospects; however, the drilling company will also contract with other entities to drill third party wells. Our management believes that the acquisition of this rig will accelerate the development of our leasehold acreage while providing an additional revenue stream through contract drilling. In January 2002, our new subsidiary company, Western Star Drilling Company ("WSDC"), was incorporated. We transferred the rig and all related equipment to WSDC in exchange for 100% of WSDC's outstanding stock. Currently, we are in discussions with our bank and expect to transfer all, or a major portion, of the associated debt to WSDC.

Mining and Manufacturing of Leonardite Products

We operate a leonardite mine and processing plant in Williston, North Dakota. Leonardite is mined from leased reserves and processed to make a basic product that can be sold as is, or blended with other substances to make several different powdered specialty products which are used primarily in the oil well drilling mud industry. Leonardite products act as a dispersant or thinner and provide filtration control when used as an additive in drilling muds. Leonardite is also sold by us for use in metal working foundries and in agricultural applications.

In 2001, our leonardite products were sold primarily to drilling mud companies located in coastal areas of the Gulf of Mexico. Demand for the plant's output is governed mainly by the level of oil and gas drilling activities, particularly in the gulf coast area, both onshore and offshore. Drilling activity has remained at relatively low levels for periods of time during the past several years. We have no significant supply contracts with individual customers.

Status of Products, Services or Industry Segments in Development

We own 84% of the voting stock of Belmont Natural Resource Company, Inc. ("BNRC"), a Washington corporation formed for the purpose of exploiting natural gas opportunities in the Pacific Northwest. BNRC owns oil and gas leases covering 3,273 gross acres (2,804 net) on a gas prospect in the State of Washington.

In addition to our three principal business segments, we own a nonproducing silver property in Arizona. (See Item 2.) We also own a minor amount of geothermal and other mineral rights in Oregon. We do not expect to devote any substantial resources to hard mineral or geothermal exploration or development in 2002.

Sources and Availability of Raw Materials and Leases

Maintaining sufficient leasehold mineral interests for oil and gas exploration and development is a primary continuing need in the oil and gas business. Management believes that our current undeveloped acreage is sufficient to meet our presently foreseeable oil and gas leasehold needs. Maintaining sufficient leasehold mineral interests for leonardite mining is also a continuing need for our mining and manufacturing of leonardite products. Management believes the leonardite held under current leases is sufficient to maintain our present output for many years. (See Item 2.)

Major Customers

In 2001, we sold our crude oil to 22 purchasers. Flint Hills Resources (formerly Koch Petroleum Group, L.P.) was the major purchaser, accounting for approximately 71% of our oil and gas revenue in 2001 or approximately 55% of our total operating revenue. Management believes there are other crude oil purchasers to whom we would be able to sell our oil if any of our current purchasers discontinued purchasing from us.

In 2001, we sold leonardite products to 35 customers. The largest customer in 2001 for leonardite products made purchases totaling 37% of our mining and manufacturing revenue or approximately 8% of our total operating revenue.

Backlog Orders, Research and Development

We do not have any material long-term or short-term contracts to supply leonardite products. All orders are reasonably expected to be filled within three weeks of receipt. From time to time, we enter into short-term contracts to deliver any quantities of oil or gas; however, no significant backlog exists. Our oil and gas division order contracts and any off-lease-marketing arrangements are typical of those in the industry with 30 to 90 day cancellation notice provisions and generally do not require long-term delivery of fixed quantities of oil or gas. We have not spent any material time or funds on research and development and do not expect to do so in the foreseeable future.

Competition

Oil and Gas In addition to being highly speculative, the oil and gas business is intensely competitive among the many independent operators and major oil companies in the industry. Many competitors possess financial resources and technical facilities greater than those available to us and they may, therefore, be able to pay more for desirable properties or to find more potentially productive prospects. However, we believe we have the ability to obtain leasehold interests which will be sufficient to meet our oil and gas needs in the foreseeable future.

Leonardite Products Uses and specifications of leonardite-based drilling mud additives are subject to change if better products are found. Our leonardite products compete with leonardite and non-leonardite products used as additives in numerous types of drilling mud. In addition, leonardite deposits are available in other areas within the United States, and competitors may be able to enter the leonardite business with relative ease. At the present time, similar products are marketed by other companies who mine, process and market leonardite products. Competition lies primarily in delivery time, transportation costs, quality of the product, performance of the product when used in drilling mud and access to high-quality leonardite deposits. In addition, higher fuel prices can significantly affect our leonardite operations because our processing is located in a colder climate.

Contract Drilling The contract drilling business is highly competitive. Contract drilling competition involves price, efficiency, rig availability, rig condition, reputation, customer relations and many other factors. Although the contract drilling rig business can be competitive, we believe there is a shortage of drilling rigs available in some areas of the Williston Basin.

Contract drilling and oil and natural gas activities are subject to a number of risks and hazards. These could cause serious injury or death to persons, suspension of drilling operations, serious damage to equipment or property of others, and damage to producing formations in surrounding areas. Our operations could also cause environmental damage, particularly through oil spills, gas leaks, discharges of toxic gases or extensive uncontrolled fires. In addition, we could become subject to liability for reservoir damages. The occurrence of a significant event, including pollution or environmental damage, could materially affect our operations and financial condition. We believe we are adequately insured or indemnified against normal and foreseeable risks in our operations in accordance with industry standards. However, such insurance or indemnification may not be adequate to protect us against liability from all consequences of well disasters, extensive fire damage or damage to the environment. Likewise, we cannot guarantee that we will be able to maintain adequate insurance in the future at reasonable rates or that any particular types of coverage will be available.

Environmental Regulations

All of our operations are generally subject to numerous stringent federal, state and local environmental regulations under various acts including the Comprehensive Environmental Response, Compensation and Liability Act; the Federal Water Pollution Control Act; and the Resources Conservation and Recovery Act.

For example, our oil and gas business segment is affected by diverse environmental regulations including those regarding the disposal of produced oilfield brines, other oil-related wastes, and wastes not directly related to oil and gas production. Additional regulations exist regarding the containment and handling of crude oil as well as preventing the release of oil into the environment and a number of others. It is not possible to estimate future environmental compliance costs due in part to the uncertainty of continually changing environmental initiatives. While future environmental cost can be expected to be significant to the entire petroleum industry, we do not believe our costs would be any more of a relative financial burden than those of our peers in the industry and that they will be a cost of doing business that will be recovered in the marketplace.

Our leonardite mining and processing segment is also subject to an abundant number of federal, state and local environmental regulations, particularly those concerned with air contaminant emission levels of our processing plant and mine permit and reclamation regulations pertaining to surface mining at our leonardite mine. We believe that maintenance of acceptable air contaminant emission levels at our processing plant could become more costly in the future if plant production increases substantially above levels experienced over the past several years. Management believes significantly higher plant utilization would increase emission levels and could make it necessary to replace or upgrade air quality control equipment. Environmental compliance costs that might be required to upgrade air quality control equipment can not be reasonably estimated because future regulatory requirements are unknown.

Foreign Operations and Export Sales

We have no production facilities or operations in foreign countries and have no direct export sales. Some of our leonardite products are sold to distributors in the United States who in turn export these products.

Employees

At March 15, 2002, we employed 16 persons on a full-time basis, including our officers. None of our employees are represented by unions. We consider our relationships with our employees to be excellent.

ITEM 2. PROPERTIES

Our properties consist of five main categories: Office, oil and gas exploration and production, oil and gas drilling rig, leonardite plant and mine, and a nonproducing silver property. Certain of these properties are mortgaged to our bank. See Note E to the Financial Statements for further information.

Office

We own an 18,000 square foot office building, which is located on a one-acre lot in Williston, North Dakota. We use about 9,000 square feet of the building and rent the remainder to unaffiliated businesses.

Oil and Gas Exploration and Production

We own developed oil and gas leases totaling 19,179 gross (14,613 net) acres as of December 31, 2001, plus associated production equipment. We also own a number of undeveloped oil and gas leases. The acreage and other additional information concerning our oil and gas operations are presented in the following tables.

Estimated Net Quantities of Oil and Gas and Standardized Measure of Future Net Cash Flows All of our oil and gas reserves are located in the United States. Unaudited information concerning the estimated net quantities of all of our proved reserves and the standardized measure of future net cash flows from the reserves is presented in Note L to the Consolidated Financial Statements. The estimates are based upon the report of Broschat Engineering and Management Services, an independent petroleum engineering firm in Williston, North Dakota. We have no long-term supply or similar agreements with foreign governments or authorities, and we do not own an interest in any reserves accounted for by the equity method.

Net Oil and Gas Production, Average Price and Average Production Cost The net quantities of oil and gas produced and sold by us for each of the last three fiscal years, the average sales price per unit sold and the average production cost per unit are presented below.

Oil & Gas

YEAR	NET OIL PROD. (BBLS)	NET GAS PROD. (MCF)	NET OIL & GAS PROD. (BOE)*	AVERAGE OIL SALES PRICE PER BBL	AVERAGE GAS SALES PRICE PER MCF	AVERAGE PROD. COST PER BOE**
2001	149,916	11,496	151,832	$ 20.25	$ 2.40	$12.23
2000	165,156	10,139	166,846	$ 26.75	$ 1.80	$ 9.94
1999	182,356	8,042	183,696	$ 14.70	$ 1.10	$ 6.61

*Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (6 MCF) of natural gas equal to one barrel of oil equivalent (1 BOE).
**Average production cost includes lifting costs, remedial workover expenses and production taxes.

Gross and Net Productive Wells As of December 31, 2001, our total gross and net productive wells were as follows:

Productive Wells*

OIL		GAS		TOTAL	
GROSS WELLS	NET WELLS	GROSS WELLS	NET WELLS	GROSS WELLS	NET WELLS
108	80.13	26	25.25	134	105.38

*There are no wells with multiple completions. A gross well is a well in which a working interest is owned. The number of net wells represents the sum of fractional working interests we own in gross wells. Productive wells are producing wells plus shut-in wells we deem capable of production.

Gross and Net Developed and Undeveloped Acres As of December 31, 2001, we had total gross and net developed and undeveloped oil and gas leasehold acres as set forth below. The developed acreage is stated on the basis of spacing units designated by state regulatory authorities.

Leasehold Acreage*

	DEVELOPED		UNDEVELOPED		TOTAL	
	GROSS	NET	GROSS	NET	GROSS	NET
Montana	9,320	7,663	31,693	32,442	41,013	40,105
North Dakota	9,859	6,950	61,978	31,090	71,837	38,040
Washington	0	0	3,273	2,804	3,273	2,804
ALL STATES	19,179	14,613	96,944	66,336	116,123	80,949

*Gross acres are those acres in which a working interest is owned. The number of net acres represents the sum of fractional working interests we own in gross acres.

Exploratory Wells and Development Wells For each of the last three fiscal years ended December 31, the number of net exploratory and development productive and dry wells drilled by us was as set forth below. Although we did not drill any productive or dry wells in 1999, we drilled 1.99 net service wells in order to attempt to increase production in a waterflood of an existing field.

YEAR	NET EXPLORATORY WELLS DRILLED		NET DEVELOPMENT WELLS DRILLED		TOTAL NET PRODUCTIVE OR DRY WELLS DRILLED
	PRODUCTIVE	DRY	PRODUCTIVE	DRY	
2001	0.00	0.00	0.00	0.00	0.00
2000	0.00	0.00	0.83	0.00	0.83
1999	0.00	0.00	0.00	0.00	0.00

Present Activities From January 1, 2002, to March 15, 2002, we drilled and completed two gross (1.99 net)development wells in the South Starbuck Madison Unit in Bottineau County, North Dakota.

Supply Contracts or Agreements We are not obligated to provide a fixed or determinable quantity of oil and gas in the future under any existing contract or agreement, beyond the short-term contracts customary in division orders and off lease marketing arrangements within the industry.

Reserve Estimates Filed with Agencies Information concerning the Company's estimated proved oil and gas reserves and discounted future net cash flows applicable thereto for fiscal 2001, 2000 and 1999 is included as unaudited information in Note L to the Consolidated Financial Statements. In 1999, information concerning portions of the Company's estimated proved oil and gas reserves was provided to the U.S. Department of Energy for fiscal 1998.

Oil and Gas Drilling Rig During 2001 we purchased and retro-fitted a drilling rig and dedicated it to a subsidiary company so it would be available to drill wells for us and other operators. We have designated this Rig E25, and it is capable of depths from 3,000 to 8,000 feet. Two of its primary components are a Drilling Structures Inc. mast rated at a 350,000 pound hook load and an Emsco Model GB-250 drawworks. It is our expectation that this rig would only be utilized to drill domestic wells, which would be located in the United States portion of the Williston Basin.

Leonardite Plant and Mine

The site of our leonardite plant covers about nine acres located one mile east of Williston in Williams County, North Dakota. We own this site and an additional 20 acres of undeveloped property. The plant has approximately 11,500 square feet of floor area consisting of warehousing and processing space. Within the plant is equipment able to process and ship approximately 3,000 tons of leonardite products per month. Finished product leonardite sales for the past three years are shown below.

YEAR	FINISHED PRODUCTS (TONS)	AVERAGE SALES PRICE PER TON
2001	9,779	$ 93.42
2000	7,696	$ 87.83
1999	7,736	$ 84.26

Our leonardite mining properties consist of a developed lease from private parties and one undeveloped lease from the United States Department of the Interior, Bureau of Land Management. The leased land is located about one mile from our plant site in Williams County, North Dakota. The private-party (fee) lease totals approximately 160 acres. The federal lease from the Bureau of Land Management (BLM) covers 160 undeveloped acres. In 1994, we formed a 240-acre logical mining unit (LMU), in accordance with BLM regulations, consisting of 80 acres of the fee lease and 160 acres of the BLM lease. This LMU allows current operations on the fee lease to satisfy diligent development and other requirements for 160 acres of the BLM lease. We believe that the leonardite contained in the 240-acre LMU is sufficient to supply our plant's raw material requirements for many years and that before these reserves were to be exhausted, we would be able to acquire other fee or federal coal leases in the same area.

Silver Property

We own seven patented mining claims and 15 unpatented mining claims in the Tonto National Forest in Pinal County, Arizona. These claims, known as the Reymert Silver Property, produced silver sporadically since the 1880's. We are in negotiations with another Arizona company to license this property for producing and marketing decorative rock, boulders, riprap, road-base material and similar commercial rock products under an agreement very similar to one with a former Arizona company that was terminated effective November 1, 2000. Some of the principals at the new company were also involved with the prior one, so they are familiar with the property. Our negotiations contemplate we would receive a 10% royalty of gross selling prices on all rock products produced and sold from the property and a minimum royalty of $250 per month. We have no plans to devote significant financial resources to this property in 2002; however, we are cooperating to have it developed for commercial rock production and continue to investigate other ways to further exploit the property.

ITEM 3. LEGAL PROCEEDINGS

We are not a party, nor are any of our properties subject, to any pending material legal proceedings. We know of no legal proceedings contemplated or threatened against us.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

During the fourth quarter of 2001, no matter was submitted to a vote of our security holders through the solicitation of proxies or otherwise.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Our Common Stock trades on the Nasdaq SmallCap Stock Market under the Symbol "GEOI". The following table sets forth for the period indicated the lowest and highest trade prices for our Common Stock as reported by the Nasdaq SmallCap Stock Market. These trade prices may represent prices between dealers and do not include retail markups, markdowns or commissions.

		TRADE PRICE	
CALENDAR		LOWEST	HIGHEST
2001	1st Quarter	$ 1.75	$ 2.12
	2nd Quarter	$ 1.68	$ 2.46
	3rd Quarter	$ 1.53	$ 2.16
	4th Quarter	$ 1.45	$ 1.70
2000	1st Quarter	$ 1.13	$ 2.25
	2nd Quarter	$ 1.25	$ 2.13
	3rd Quarter	$ 1.63	$ 2.50
	4th Quarter	$ 1.94	$ 2.44

As of March 15, 2002, there were approximately 1,300 holders of record of our Common Stock. We believe that there are also approximately 750 additional beneficial owners of Common Stock held in "street name".

We have never declared or paid a cash dividend on our Common Stock nor do we anticipate that dividends will be paid in the near future. Further, certain of our financing agreements restrict the payment of cash dividends. See Note E to the Financial Statements for further information.

ITEM 6. SELECTED FINANCIAL DATA

	2001	2000	1999	1998	1997
Operating Revenue	$ 3,977,703	$ 5,112,206	$ 3,340,489	$ 2,380,651	$ 4,189,793
Net Income (Loss)	41,818	1,414,797	481,552	(1,605,218)	766,265
Net Income (Loss) Per Share	.01	.36	.12	(.39)	.19
AT YEAR END:					
Total Assets	8,201,719	7,450,286	7,328,840	6,704,724	8,032,328
Long-term Debt	1,035,228	375,000	1,610,008	1,625,004	666,000
Current Maturities	125,000	125,000	175,000	316,000	457,097
Working Capital (deficit)	(223,782)	423,897	638,549	111,515	18,240
Stockholders' Equity	5,536,009	5,712,655	4,462,475	4,052,114	5,691,597

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

We operate through three primary segments: 1) oil and gas exploration and production; 2) oil and gas drilling; and 3) leonardite mining and processing. Our major leonardite products are oil and gas drilling mud additives.

BUSINESS ENVIRONMENT AND RISK FACTORS

This discussion and analysis of financial condition and results of operations, and other sections of this report, contain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are based on management's beliefs, assumptions, current expectations, estimates and projections about the oil, gas and leonardite industry, the economy and about us. Words such as "may," "will," "expect," "anticipate," "estimate" or "continue," or comparable words are intended to identify forward-looking statements. These statements are not guarantees of future performance and involve risks, uncertainties and assumptions that are difficult to predict with regard to timing, extent, likelihood and degree of occurrence. Therefore, our actual results and outcomes may materially differ from what may be expressed or forecasted in our forward-looking statements. Furthermore, we undertake no obligation to update, amend or clarify forward-looking statements, whether as a result of new information, future events or otherwise.

Important factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to, changes in production volumes; worldwide supply and demand which affect commodity prices for oil; the timing and extent of our success in discovering, acquiring, developing and producing oil, natural gas and leonardite reserves; risks inherent in the drilling and operation of oil and natural gas wells and the mining and processing of leonardite products; future production and development costs; the effect of existing and future laws, governmental regulations and the political and economic climate of the United States; and conditions in the capital markets.

CRITICAL ACCOUNTING POLICIES

Certain accounting policies are very important to the portrayal of Company's financial condition and results of operations and require management's most subjective or complex judgments. The policies are as follows:

Oil and Gas Properties

We employ the full cost method of accounting for our oil and gas production assets. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized. The sum of net capitalized costs and estimated future development and dismantlement costs is depleted on the unit-of-production basis using proved oil and gas reserves as determined by independent petroleum engineers.

Reserve engineering is a subjective process that is dependent on the quality of available data and on engineering and geological interpretation and judgment. Reserve estimates are subject to change over time as additional information becomes available. If the estimate of proved reserve volumes declines or the estimate of future development costs increases, our depletion increases, which reduces our net income.

Also under the full cost method, we are required to record a permanent impairment provision if the net book value of our oil and gas properties less related deferred taxes exceeds a ceiling value equal to the present value of the future cash inflows from proved reserves, tax effected and discounted at 10%. The ceiling test is computed at the end of each quarter. The oil and gas prices used in calculating future cash inflows are based upon the market price on the last day of the accounting period. Oil and gas prices are generally volatile and if the market prices at a period end date have decreased, we may have to record an impairment.

Revenue Recognition

Oil revenues are recognized when production is delivered.

Impairment of Long-Lived Assets

Potential impairment of long-lived assets (other than oil and gas properties) is reviewed whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. Impairment is recognized when the estimated future net cash flows (undiscounted and without interest charges) from the asset are less than the carrying amount of the asset. No impairment losses have been recognized on long-lived assets.

Accounting for Income Taxes

As part of the process of preparing our consolidated financial statements, we are required to estimate our income taxes. This process involves estimating our current tax exposure together with assessing temporary differences resulting from the differing treatment of items for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within our consolidated balance sheet. We regularly review our deferred tax assets for recoverability based on historical taxable income, projected future taxable income, and the expected timing of the reversals of existing temporary differences. To the extent we believe that recovery is not likely, we must establish a valuation allowance. We have recorded a valuation allowance due to uncertainties related to our ability to utilize some of our statutory depletion carryforward. After recognition of this allowance, our combined net deferred tax assets and deferred tax liabilities result in a net long-term liability. To the extent we increase or decrease the allowance in a period, we must include an expense or benefit within the tax provision in the statement of operations. Significant management judgment is required in determining our provision for income taxes, deferred tax assets and liabilities and the valuation allowance recorded against our deferred tax assets.

Off Balance Sheet Arrangements

We have no off balance sheet arrangements, special purpose entities, financing partnerships or guarantees.

New Accounting Standards

In June 2001, the FASB issued Statement No. 143 (FAS 143) titled "Accounting for Asset Retirement Obligations". Effective for fiscal years beginning after June 15, 2002, FAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The liability is to be discounted and accretion expense recognized using the credit-adjusted-risk-free interest rate in effect when the liability was initially recognized. Upon initial application of the statement, an entity is to 1)recognize a liability for any existing asset retirement obligations adjusted for the cumulative accretion to the date of adoption of the statement and 2)recognize an asset for retirement costs capitalized as an increase to the carry amount of the associated long-lived asset adjusted for the accumulated depreciation on that capitalized cost to the date of adoption of the statement. The Company is currently assessing the impact adopting FAS 143 will have on the Company's financial position and operations.

RESULTS OF OPERATIONS

Comparison of 2001 to 2000 Revenue and Gross Margin

Oil and gas sales were $3,064,000 in 2001 compared to $4,436,000 in 2000, a decrease of $1,372,000 or 31%. This decline in revenue was largely due to a 24% decrease in the average value we received for our oil production during 2001. The 2001 average oil price per barrel was $20.25 compared to an average of $26.75 in 2000 and $14.70 in 1999. Occasionally, we consider the use of various New York Mercantile Exchange (NYMEX) financial instruments to hedge against the risks of oil price declines. See Note J to the Financial Statements for further information. The volume of oil and gas sold in 2001 decreased 15,000 barrels of oil equivalent (BOE) or 9% to 152,000 BOE from 167,000 BOE in 2000. The lower 2001 production volumes sold principally followed the approximate average production decline of our wells, as a lack of rig availability and other oilfield supplies and services severely hampered our drilling plans. For example, we entered into a contract to drill a well in mid-August 2001 with the only contractor available to us. Due entirely to that contractor's schedule, the well was not drilled until mid-January 2002, some five months later. This was unacceptable to us and led to our decision to get involved with drilling operations as discussed below.

Oil and gas production costs in 2001 were $1,856,000 compared to $1,659,000 in 2000, an increase of $197,000 or 12%. These higher costs were due to two primary factors, an increase of $101,000 in repairs and maintenance costs that were incurred to make discretionary improvements to existing facilities during this period of higher cash flow, and generally higher costs of petroleum-related supplies and services including, for example, propane, electricity, treating chemicals and contract labor. Production costs expressed on a per equivalent barrel basis increased $2.29 per BOE or 23% to average $12.23 for 2001 compared to $9.94 for 2000. The increase in per barrel costs occurred as we produced more of our marginal (higher cost per barrel) wells in the oil price environment existing in the first three quarters of 2001 and performed workovers in lieu of drilling to try to maintain production. Our gross margin for 2001 oil and gas operations without deductions for depletion and selling, general and administrative (SG&A) expenses, decreased to $1,208,000 or 39% of revenue compared to $2,777,000 or 63% of revenue for the year 2000.

During 2000 and 2001, most operators gained confidence in sustained higher energy prices that existed prior to September 11, 2001, and consequently demand for oilfield supplies and services, particularly drilling services, increased substantially. This put a strain on available resources which were already in tight supply from years of reduced activity. In north central North Dakota, the only remaining drilling contractor with a rig dedicated to the area has a corporate relationship with another operator that is a private oil and gas company that is a competitor of ours in exploration and production and acquisition activities. This fact and the unavailability of timely drilling services encouraged us to become involved in drilling operations. In September 2001, we decided to fund the acquisition and retrofitting of a drilling rig to meet our future drilling needs as well as that of other operators in the core areas of our operations, principally the Williston Basin East Flank. No actual drilling operations were commenced in 2001, but all rig rebuilding was completed and the rig spudded its first well for us on January 2, 2002. This rig is held in a North Dakota private company named Western Star Drilling Company ("WSDC") that at this time is a wholly-owned subsidiary of GeoResources, Inc. See Note A to the Financial Statements for further information.

Leonardite product sales were $914,000 in 2001 compared to $676,000 in 2000, an increase of $238,000 or 35%. This increase was due to a combination of several factors, the main one being the increased activity of drilling in the Gulf of Mexico. Another factor was a 6% increase in average price per ton for leonardite sold in 2001 resulting from a slightly higher demand for our specialty products, which have higher selling prices and an increase in our base price for leonardite. Production sold in 2001 was 9,779 tons at an average price of $93.42 compared to 7,696 tons at an average price of $87.83 for 2000.

Cost of leonardite sold was $824,000 in 2001 compared to $669,000 in 2000, an increase of $155,000 or 23%. Average production costs per ton were $84.29 and $86.91 for 2001 and 2000, respectively. Costs per ton decreased approximately 3% for 2001 compared to 2000 due mainly to increased production which spread fixed costs over a larger volume.

Gross margin for 2001 leonardite operations before deductions for depreciation and selling, general and administrative expenses was $89,000 or 10% of revenue compared to $7,000 or 1% of revenue for 2000. The increase in 2001 gross margin was primarily the result of the higher price per ton discussed above.

Comparison of 2001 to 2000 Consolidated Analysis

Total revenue for 2001 decreased $1,134,000 or 22% to $3,978,000 from $5,112,000 in 2000. This decrease was due to the lower average oil price and the 9% lower oil production in 2001 compared to 2000.

Total operating costs for 2001 increased by $489,000 or 14% to $3,897,000 compared to $3,408,000 in 2000. This increase in total costs resulted from increases in oil and gas production costs and costs of leonardite sold, as previously discussed, coupled with smaller increases in the other expense categories. Depreciation, depletion and amortization expense in 2001 was $745,000 or 10% higher than 2000, due to reserve values and volumes being evaluated at substantially lower prices at year end 2001 compared to year end 2000. Selling, general and administrative costs (SG&A) were $66,000 or 16% higher in 2001 compared to 2000 due to an increase in our level of operations in 2001, and the addition of one administrative employee.

Lower 2001 total revenue and higher total operating costs resulted in operating income of $81,000 for 2001 compared to income of $1,704,000 in 2000. Nonoperating expenses declined from $97,000 in 2000 to $2,000 in 2001, due to lower interest expense. Income before taxes in 2001 was $79,000 compared to income of $1,608,000 in 2000.

Provisions for income tax expense in 2001 was $37,000 compared to $193,000 in 2000. The amount for each year is primarily reflective of changes in our tax-deferred assets and liabilities under the provisions of SFAS No. 109. See Notes A and F to the Financial Statements for further information.

As a result of all the factors discussed above, net income for 2001 was $42,000 or $0.01 per share compared to a net income of $1,415,000 or $0.36 per share in 2000.

Comparison of 2000 to 1999 Revenue and Gross Margin

Oil and gas sales were $4,436,000 in 2000 compared to $2,689,000 in 1999, an increase of $1,747,000 or 65%. This increase in revenue was essentially due to an 82% increase in the average value we received for our oil production during 2000. The 2000 average oil price per barrel was $26.75 compared to an average of $14.70 in 1999. We periodically use various New York Mercantile Exchange (NYMEX) crude oil and energy products contracts and options to hedge against the risks of oil price declines. See Note J to the Financial Statements for further information. The volume of oil and gas sold in 2000 decreased 17,000 barrels of oil equivalent (BOE) or 9% to 167,000 BOE from 184,000 BOE in 1999. The higher 2000 average oil price resulted from a continuing increase in world oil prices that occurred during early 2000 and the relative stability of those higher levels through the remainder of the year. The lower 2000 production volumes sold are somewhat skewed when compared solely with 1999, because volumes in that year were higher due to sales out of inventory held over from 1998 during a period of severely depressed prices. Over the four years from 1997 through 2000, our volumes sold declined from 213,000 to 167,000 or 7% per year, which we believe to be more representative of the approximate average decline of our production base. During the period of 1998 through 2000, little new drilling was done by our company due first to periods of extremely low prices and later to our desire to retire a substantial portion of our debt.

Oil and gas production costs in 2000 were $1,659,000 compared to $1,214,000 in 1999, an increase of $445,000 or 37%. These higher costs were due to three primary factors: (i) an increase of $121,000 in repairs and maintenance costs that were incurred to make discretionary improvements to existing facilities during this period of higher cash flow, (ii) an increase of $103,000 in state severance taxes that were directly related to higher oil revenue and (iii) generally higher costs of petroleum-related supplies and services including, for example, propane, electricity, treating chemicals and contract labor. Production costs expressed on a per equivalent barrel basis increased $3.33 per BOE or 50% to average $9.94 for 2000 compared to $6.61 for 1999. The increase in per barrel costs occurred because we were able to produce more of our marginal (higher cost per barrel) wells in the oil price environment existing in 2000 than in 1999. Gross margin for 2000 oil and gas operations before deductions for depletion and selling, general and administrative (SG&A) expenses, increased to $2,777,000 or 63% of revenue compared to $1,474,000 or 55% of revenue for 1999.

Leonardite product sales were $676,000 in 2000 compared to $652,000 in 1999, an increase of $24,000 or 4%. This increase was entirely due to a 4% increase in average price per ton for leonardite sold in 2000 resulting from a slightly higher demand for our specialty products, which have higher selling prices. Production sold in 2000 was 7,696 tons at an average price of $87.83 compared to 7,736 tons at an average price of $84.26 for 1999.

Cost of leonardite sold was $669,000 in 2000 compared to $563,000 in 1999, an increase of $106,000 or 19%. Average production costs per ton were $86.92 and $72.79 for 2000 and 1999, respectively. Costs per ton increased approximately 19% for 2000 compared to 1999 due in part to the sales of more specialty products that have higher processing costs but mainly due to the significant increase in natural gas prices. Natural gas is used in the drying portion of leonardite processing.

Gross margin for 2000 leonardite operations before deductions for depreciation and selling, general and administrative expenses was $7,000 or 1% of revenue compared to $89,000 or 14% of revenue for 1999. The decline in 2000 gross margin was primarily a result of the high natural gas prices discussed above.

Comparison of 2000 to 1999 Consolidated Analysis

Total revenue for 2000 increased $1,772,000 or 53% to $5,112,000 from $3,340,000 in 1999. This increase was in essence due to the substantially higher oil prices that existed during the entire year of 2000 compared to 1999, particularly the first half of 1999.

Total operating costs for 2000 also increased by $687,000 or 25% to $3,408,000 compared to $2,720,000 in 1999. This increase in total costs resulted from increases in oil and gas production costs and costs of leonardite sold, as previously discussed, coupled with smaller increases in the other expense categories. Depreciation, depletion and amortization expenses were relatively unchanged in 2000 at $674,000 or 6% higher than 1999. Selling, general and administrative costs (SG&A), however, were $98,000 higher in 2000 or 32% compared to 1999. Actually SG&A costs were unusually low in 1999 due to salary reductions and other cost cutting measures during the time of low oil prices.

Higher 2000 total revenue and higher total operating costs resulted in operating income of $1,704,000 for 2000 compared to income of $620,000 in 1999. Nonoperating expenses declined somewhat, from $113,000 in 1999 to $97,000 in 2000, primarily due to lower interest expense as we reduced debt. Income before taxes in 2000 was $1,608,000 compared to income of $508,000 in 1999.

Income tax expense in 2000 was $193,000 compared to $26,000 in 1999. The amount for each year is primarily reflective of changes in our tax-deferred assets and liabilities under the provisions of SFAS No. 109. See Notes A and F to the Financial Statements for further information.

As a result of all the factors discussed above, net income for 2000 was $1,415,000 or $0.36 per share compared to a net income of $482,000 or $0.12 per share in 1999.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2001, we had current assets of $1,063,000 compared to current liabilities of $1,286,000 for a current ratio of .83 to 1 and working capital deficit of $224,000. This compares to a current ratio of 1.39 to 1 at December 31, 2000, and working capital of $424,000.

During the year ended December 31, 2001, we generated cash flows from operating activities of $1,192,000, which was $1,112,000 less than the amount generated during 2000. This decrease was essentially due to lower oil prices and production discussed previously. We anticipate that cash flows from operations and funds available under our $3,000,000 revolving line of credit ("RLOC") will be sufficient to meet our short-term cash requirements. The RLOC, which had an available balance of $2,225,000 at December 31, 2001, allows borrowing until January 5, 2004, with repayment due by January 5, 2008.

During 2001, our investing activities used $1,844,000 of cash for additions to property, plant and equipment. Approximately $968,000 of these additions was made to purchase and retrofit a drilling rig. In addition, $544,000 of capitalized costs was used to set up a centralized production facility in our South Starbuck Madison Unit, a secondary recovery unit in Bottineau County, North Dakota; a re-entry project in Stark County, North Dakota, and to pay our share of completion costs on a Red River well in Montana where we own an 8% working interest. Portions of the remaining $332,000 used in investing activities consisted of $24,000 for miscellaneous office and leonardite plant expenditures, $135,000 for unproved oil and gas property costs and $31,000 for proved property acquisition costs.

During 2001, our financing activities consisted of $115,000 of cash utilized for regularly scheduled principal payments under long-term debt agreements, and we used an additional $220,000 of cash to purchase our common stock on the open market. During the second half of 2001, we borrowed $775,000 on our RLOC to finance the purchase and retrofitting of our drilling rig.

We estimate that our development costs for 2002 relating to our proved developed nonproducing and proved undeveloped oil and gas properties will be approximately $1,050,000. Planned expenditures for 2002 also include delay rentals and other exploration costs of approximately $100,000. Capital expected to be used for 2002 principal payments required under existing debt agreements is $125,000.

We expect to continue to evaluate possible future purchases of additional producing oil and gas properties and the further development of our properties. We believe our long-term cash requirements for such investing activities and the repayment of long-term debt can be met by future cash flows from operations and, if necessary, possible forward sales of oil reserves or additional debt or equity financing.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

See "Index to Consolidated Financial Statements" on page 25.

ITEM 9. DISAGREEMENTS ON ACCOUNTING AND FINANCIAL DISCLOSURES

Not applicable.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following sets forth certain information concerning each of our directors and executive officers:

NAME AND AGE	POSITION(S) WITH THE COMPANY	PERIOD OF SERVICE AS A DIRECTOR OR OFFICER
Jeffrey P. Vickers Age: 49	President and Director	Since 1982
Jeffrey B. Jennings Age: 45	Vice President of Land and Finance	Since June 2000
Thomas F. Neubauer Age: 67	Vice President of Leonardite Operations	Since June 1992
Cathy Kruse Age: 47	Secretary and Director	Since October 1981 (officer); and since June 1996 (director)
Connie R. Hval Age: 41	Treasurer	Since June 2000
H. Dennis Hoffelt Age: 61	Director Member of Audit Committee	From 1967 through June 1986; and since June 1987
Paul A. Krile Age: 74	Director Member of Audit Committee	Since June 1997
Duane Ashley Age: 54	Director Member of Audit Committee	Since June 1999

All of the directors' terms expire at the next annual meeting of shareholders or when their successors have been elected and qualified. Our executive officers serve at the discretion of the Board of Directors. The Board of Directors has an audit committee consisting of Duane Ashley, H. Dennis Hoffelt and Paul A. Krile.

Jeffrey P. Vickers received a Bachelor of Science degree in Geological Engineering with a Petroleum Engineering option from the University of North Dakota in 1978. Prior to obtaining his degree, Mr. Vickers served two years overseas with the U.S. Army. In 1979, Mr. Vickers joined Amerada Hess Corporation as an Associate Petroleum Engineer in the Williston Basin. In 1981, Mr. Vickers was employed by us as our Drilling and Production Manager where he was responsible for providing technical assistance and supervision of drilling and production operations and generated development drilling programs. He became our President on January 1, 1983. In June 1982, Mr. Vickers became a director.

Jeffrey B. Jennings is Vice President of Land and Finance. Mr. Jennings received a Bachelor of Science in Geological Engineering in 1980 and a Master of Science in Mineral Economics in 1992, from the Colorado School of Mines. He was a consultant for us for two years prior to his employment with us in January 1996.

Thomas F. Neubauer is Vice President of Leonardite Operations and our plant manager. Mr. Neubauer has been employed by us since July 1965.

Cathy Kruse is our Secretary and business office manager. Ms. Kruse graduated from the Atlanta College of Business in 1977 and was employed as a Legal Assistant for four years prior to her employment with us in May 1981. In June 1996, Ms. Kruse became a director.

Connie R. Hval is our Treasurer and comptroller. Ms. Hval graduated from the University of North Dakota – Williston in December 1980 and became employed with us in January 1981.

H. Dennis Hoffelt has been President of Triangle Electric Inc., Williston, North Dakota, an electrical contracting firm, for over the past five years. He served as one of our directors from 1967 through June of 1986 and was elected as a director again in 1987.

Paul A. Krile has been one of our directors since June 1997. He has been the President and owner of Ranco Fertiservice, a manufacturer of dry fertilizer handling equipment, headquartered in Sioux Rapids, Iowa for more than the last five years.

Duane Ashley has been one of our directors since June 1999. He is a Senior Salesman for Weatherford Enterra Inc. since September 2000 and for five years prior to January 1999. From January 1999 through August 2000 he was a Senior Salesman for GRACO Fishing and Rental Tool, Inc.

Cathy Kruse is the sister-in-law of Jeffrey P. Vickers. No other family relationship exists between or among any of the officers or nominees. There are no arrangements or understandings between any of the directors or nominees and any other person pursuant to which any person was or is to be elected as a director or nominee.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors and executive officers, and persons who own more than 10% of our common stock to file with the Securities and Exchange Commission initial reports of ownership and reports of changes in ownership of our common stock. Executive officers, directors and greater than 10% shareholders are required by SEC regulations to furnish us with copies of all Section 16(a) reports they file. To our knowledge, based solely on review of the copies of such reports furnished to us or advice that no filings were required during fiscal year 2001, all executive officers, directors and greater than 10% beneficial owners complied with the Section 16(a) filing requirements.

ITEM 11. EXECUTIVE COMPENSATION

The following table presents the aggregate compensation which was earned by our Chief Executive Officer for each of the past three years. We do not have an employment contract with any of our executive officers. None of our employees earned total annual salary and bonus in excess of $100,000. There has been no compensation awarded to, earned by or paid to any employee required to be reported in any table or column in any fiscal year covered by any table, other than what is set forth in the following table.

Summary Compensation Table

					LONG TERM COMPENSATION			
	ANNUAL COMPENSATION				AWARDS		PAYOUTS	
NAME AND PRINCIPAL POSITION	YEAR	SALARY ($)	BONUS ($)	OTHER ANNUAL COMPEN-SATION	RESTRICTED STOCK AWARD(S) ($)	SECURITIES UNDERLYING OPTIONS SARS(#)	LTIP PAYOUTS ($)	ALL OTHER COMPEN-SATION ($)
Jeffrey P. Vickers CEO	2001	$90,579	-0-	-0-	N/A	-0-	N/A	$4,529
	2000	$84,978	-0-	-0-	N/A	-0-	N/A	$6,091
	1999	$76,307	-0-	-0-	N/A	-0-	N/A	$8,722

In the preceding table, the column titled "All Other Compensation" is comprised entirely of profit sharing amounts and the 401(k) Company matching funds discussed below.

If we achieve net income in a fiscal year, our Board of Directors may determine to contribute an amount based on our profits to the Employees' Profit Sharing Plan and Trust (the "Profit Sharing Plan"). An eligible employee may be allocated from 0% to 15% of his other compensation depending upon the total contribution to the Profit Sharing Plan. A total of 20% of the amount allocated to an individual vests after three years of service, 40% after four years, 60% after five years, 80% after six years and 100% after seven or more years. On retirement, an employee is eligible to receive the vested amount. On death, 100% of the amount allocated to an individual is payable to the employee's beneficiary. We made total contributions to the Profit Sharing Plan, matching and discretionary, for the years ended December 31, 2001, 2000 and 1999 of $24,614, $36,474, and $37,312, respectively. As of December 31, 2001, vested amounts in the Profit Sharing Plan for all officers as a group was approximately $613,000.

Effective July 1, 1997, we executed an Adoption Agreement Nonstandardized Code 401(k) Profit Sharing Plan that incorporated a 401(k) Plan into the existing Profit Sharing Plan. Eligible employees are allowed to defer up to 15% of their compensation and we match up to 5%.

Aggregated Option Exercises In Last Fiscal Year and Fiscal Year-End Option Values

The following table summarizes for our Chief Executive Officer (i) the total number of shares received upon exercise of stock options during the fiscal year ended December 31, 2001, (ii) the aggregate dollar value realized upon such exercise, (iii) the total number of unexercised options, if any, held at December 31, 2001, and (iv) the value of unexercised in-the-money options, if any, held at December 31, 2001.

In-the-money options are options where the fair market value of the underlying securities exceeds the exercise or base price of the option. The aggregate value realized upon exercise of a stock option is the difference between the aggregate exercise price of the option and the fair market value of the underlying stock on the date of exercise. The value of unexercised, in-the-money options at fiscal year-end is the difference between the exercise price of the option and the fair market value of the underlying stock on December 31, 2001, which was $1.55 per share. With respect to unexercised, in-the-money options, the underlying options have not been exercised, and actual gains, if any, on exercise will depend on the value of our Common Stock on the date of exercise.

NAME	SHARES ACQUIRED ON EXERCISE(#)	VALUE REALIZED($)	NUMBER OF UNEXERCISED OPTIONS/SARS AT FY-END(#) EXERCISABLE/ UNEXERCISABLE	VALUE OF UNEXERCISED IN-THE-MONEY OPTIONS/SARS AT FY-END($) EXERCISABLE/ UNEXERCISABLE
Jeffrey P. Vickers, CEO	-0-	-0-	71,000/0	0/0

Option Grants In Last Fiscal Year

At our 1993 Annual Meeting of Shareholders, a 1993 Employees' Incentive Stock Option Plan (the "Plan") was approved by shareholders. The purpose of the Plan is to enable us to attract persons of training, experience and ability to continue as employees and to furnish additional incentive to them, upon whose initiative and efforts the successful conduct and development of our business largely depends, by encouraging them to become owners of our Common Stock.

The term of the Plan expires on February 17, 2003. If within the duration of an option, there is a corporate merger consolidation, acquisition of assets or other reorganization and if this transaction affects the optioned stock, the optionee will thereafter be entitled to receive upon exercise of his option those shares or securities that he would have received had the option been exercised prior to the transaction and the optionee had been a stockholder with respect to such shares.

Our Board of Directors administers the Plan. The exercise price of the Common Stock offered to eligible participants under the Plan by grant of an option to purchase Common Stock may not be less than the fair market value of the Common Stock at the date of grant; provided, however, that the exercise price will not be less than 110% of the fair market value of the Common Stock on the date of grant in the event an optionee owns 10% or more of the Common Stock. A total of 300,000 shares have been reserved for issuance pursuant to options to be granted under the Plan. Of the 300,000 reserved shares, options are issued for 178,000 shares at an average exercise price of $2.34, and 98,000 shares remain in the plan that could be granted.

No grants of stock options were made by the Company during the fiscal year ended December 31, 2001.

Directors' Compensation

We pay each director who is not also an employee $200 per month and reimburse the directors for travel expenses.

ITEM 12. SECURITIES OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the number of shares of our Common Stock beneficially owned by each of our officers and directors and by all directors and officers as a group, as of March 15, 2002. Unless otherwise indicated, the shareholders listed in the table have sole voting and investment powers with respect to the share indicated.

CLASS OF SECURITIES	NAME OF PERSON OR NUMBER OF DIRECTORS AND OFFICERS AS A GROUP	AMOUNT OF SHARES AND NATURE OF BENEFICIAL OWNERSHIP	PERCENT OF CLASS
Common Stock, $.01 par value	Jeffrey P. Vickers	331,934-Direct and Indirect(a)	8.8%
Common Stock, $.01 par value	Paul A. Krile	253,000-Direct	6.7%
Common Stock, $.01 par value	Cathy Kruse	13,700-Direct(c)	(b)
Common Stock, $.01 par value	Thomas F. Neubauer	20,500-Direct(d)	(b)
Common Stock, $.01 par value	H. Dennis Hoffelt	41,000-Direct and Indirect(e)	1.1%
Common Stock, $.01 par value	Connie R. Hval	9,500-Direct(f)	(b)
Common Stock, $.01 par value	Jeffrey B. Jennings	11,500-Direct(g)	(b)
Common Stock, $.01 par value	Duane Ashley	0-Direct and Indirect	(b)

CLASS OF SECURITIES	NAME OF PERSON OR NUMBER OF DIRECTORS AND OFFICERS AS A GROUP	AMOUNT OF SHARES AND NATURE OF BENEFICIAL OWNERSHIP	PERCENT OF CLASS
Common Stock, $.01 par value	Officers and Directors as a Group- (eight persons)	681,134-Direct and Indirect	18.0%

(a) Includes 139,634 shares owned directly by Mr. Vickers, 2,500 in a self-directed individual retirement account, 72,000 shares held jointly with his wife, Nancy J. Vickers, 25,500 shares held directly by his wife, 1,300 shares in his wife's self-directed individual retirement account, and an aggregate 20,000 shares held by him as custodian for his children. Also included are 71,000 shares that may be purchased by Mr. Vickers under presently exercisable stock options granted pursuant to our 1993 Employees' Incentive Stock Option Plan.

(b) Less than 1%.

(c) Included are 9,500 shares which may be purchased by Ms. Kruse under presently exercisable stock options granted pursuant to our 1993 Employees' Incentive Stock Option Plan.

(d) Included are 9,500 shares which may be purchased by Mr. Neubauer under presently exercisable stock options granted pursuant to our 1993 Employees' Incentive Stock Option Plan.

(e) Mr. Hoffelt has sole voting and investment power over 11,500 of shares and has shared voting and investment powers over the remaining 29,500 shares.

(f) Included are 9,500 shares which may be purchased by Ms. Hval under presently exercisable stock options granted pursuant to our 1993 Employees' Incentive Stock Option Plan.

(g) Included are 9,500 shares which may be purchased by Mr. Jennings under presently exercisable stock options granted pursuant to our 1993 Employees' Incentive Stock Option Plan.

The following table sets forth information concerning persons known to us to be the beneficial owners of more than 5% of our outstanding Common Stock as of March 15, 2002.

CLASS OF SECURITIES	NAME AND ADDRESS OF PERSON	AMOUNT OF SHARES AND NATURE OF BENEFICIAL OWNERSHIP	PERCENT OF CLASS
Common Stock, $.01 par value	Jeffrey P. Vickers 1814 14th Ave. W. Williston, ND 58801	331,934-Direct and Indirect(a)	8.8%
Common Stock, $.01 par value	Paul A. Krile P. O. Box 329 Sioux Rapids, IA 50585	253,000-Direct	6.7%
Common Stock, $.01 par value	Kyle Krueger 3934 Bayshore Blvd NE St. Petersburg, FL 33073	190,900-Direct Indirect(b)(c)	5.0%

(a) See footnote (a) of the immediately preceding table

(b) This information was obtained from our transfer agent, Wells Fargo Bank Minnesota, N.A., on March 12, 2002 and the Depository Trust Company's non-objecting beneficial owners' list dated December 31, 2001.

(c) Includes 108,000 shares owned by Apollo Capital Management Group, 54,700 shares owned by Apollo Micro Cap Fund and 27,000 shares held jointly with his wife Anne Krueger.

We are not aware of any arrangements which could, at a subsequent date, result in a change in control of the company.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

There are no transactions or series of similar transactions since the beginning of our last fiscal year or any currently proposed transaction or series of similar transactions to which we were or are to be a party, and which the amount involved exceeds $10,000 and in which any director, executive officer, principal shareholder or any member of their immediate family had or will have a direct or indirect material interest.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) Documents filed as Part of this Report

(1) Financial Statements and Schedules See "Index to Consolidated Financial Statements" on next page. There are no financial statement schedules filed herewith.

(2) Exhibits See "Exhibit Index" on page 50.

(b) Reports on Form 8-K
None.

(c) Exhibits required by Item 601 of Regulation S-K
See (a)(2) above.

(d) Financial Statement Schedules required by Regulation S-X
See (a)(1) above.

GEORESOURCES, INC., AND SUBSIDIARY
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT AUDITORS ON THE CONSOLIDATED FINANCIAL STATEMENTS

To the Board of Directors and Shareholders
GeoResources, Inc.

We have audited the accompanying consolidated balance sheets of GeoResources, Inc., and Subsidiary as of December 31, 2001 and 2000, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years ended December 31, 2001, 2000 and 1999. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of GeoResources, Inc., and Subsidiary as of December 31, 2001 and 2000, and the results of its operations and its cash flows for the years ended December 31, 2001, 2000 and 1999, in conformity with accounting principles generally accepted in the United States of America.

/s/ Richey, May & Co., P. C.
Greenwood Village, Colorado
March 2, 2002

GEORESOURCES, INC., AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2001 AND 2000

ASSETS

	2001	2000
CURRENT ASSETS:		
Cash and equivalents	$ 191,328	$ 315,191
Trade receivables, net	626,359	923,173
Inventories	196,858	248,505
Prepaid expenses	48,155	15,659
Total current assets	1,062,700	1,502,528
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Oil and gas properties, using the full cost method of accounting:		
Properties being amortized	21,594,355	20,647,855
Properties not subject to amortization	239,067	119,517
Drilling rig and equipment	968,064	--
Leonardite plant and equipment	3,244,605	3,242,105
Other	759,742	737,925
	26,805,833	24,747,402
Less accumulated depreciation, depletion, amortization and impairment	(19,689,932)	(18,945,190)
Net property, plant and equipment	7,115,901	5,802,212
OTHER ASSETS:		
Mortgage loans receivable, related party	--	103,321
Other	23,118	42,225
Total other assets	23,118	145,546
TOTAL ASSETS	$ 8,201,719	$ 7,450,286

LIABILITIES AND STOCKHOLDERS' EQUITY

	2001	2000
CURRENT LIABILITIES:		
Accounts payable	$ 938,807	$ 685,909
Income taxes payable	--	75,000
Accrued expenses	222,675	192,722
Current maturities of long-term debt	125,000	125,000
Total current liabilities	1,286,482	1,078,631
LONG-TERM DEBT, less current maturities	1,035,228	375,000
DEFERRED INCOME TAXES	344,000	284,000
Total liabilities	2,665,710	1,737,631
CONTINGENCIES (NOTE H)		
STOCKHOLDERS' EQUITY:		
Common stock, par value $.01 per share; authorized 10,000,000 shares; issued and outstanding, 3,794,227 and 3,912,502 shares, respectively	37,942	39,125
Additional paid-in capital	395,290	612,571
Retained earnings	5,102,777	5,060,959
Total stockholders' equity	5,536,009	5,712,655
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 8,201,719	$ 7,450,286

The accompanying notes are an integral part of these consolidated financial statements.

GEORESOURCES, INC., AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF OPERATIONS
YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999

	2001	2000	1999
OPERATING REVENUE:			
Oil and gas sales	$ 3,064,135	$ 4,436,278	$ 2,688,642
Leonardite sales	913,568	675,928	651,847
	3,977,703	5,112,206	3,340,489
OPERATING COSTS AND EXPENSES:			
Oil and gas production	1,856,159	1,659,260	1,214,169
Cost of leonardite sold	824,296	668,849	563,081
Depreciation, depletion and amortization	744,742	674,020	635,797
Selling, general and administrative	471,517	405,622	307,336
	3,896,714	3,407,751	2,720,383
Operating income	80,989	1,704,455	620,106
OTHER INCOME (EXPENSE):			
Interest expense	(44,834)	(140,696)	(165,395)
Interest income	20,294	24,408	27,591
Other income and losses, net	22,369	19,630	25,250
	(2,171)	(96,658)	(112,554)
Income before income taxes	78,818	1,607,797	507,552
INCOME TAX EXPENSE	(37,000)	(193,000)	(26,000)
Net income	$ 41,818	$ 1,414,797	$ 481,552
EARNINGS PER SHARE:			
Net income, basic and diluted	$ .01	$ .36	$ .12
Weighted average number of shares outstanding	3,846,176	3,958,204	4,040,425
Dilutive potential shares – Stock options	--	--	--
Adjusted weighted average shares	3,846,176	3,958,204	4,040,425

The accompanying notes are an integral part of these consolidated financial statements.

GEORESOURCES, INC., AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999

	Common Stock		Additional Paid-in	Retained	
	Shares	Amount	Capital	Earnings	Total
Balance, December 31, 1998	4,071,652	$ 40,717	$ 846,787	$ 3,164,610	$ 4,052,114
Purchase of common stock	(66,300)	(663)	(70,528)	--	(71,191)
Net income	--	--	--	481,552	481,552
Balance, December 31, 1999	4,005,352	40,054	776,259	3,646,162	4,462,475
Stock options exercised	6,500	65	7,410	--	7,475
Purchase of common stock	(99,350)	(994)	(171,098)	--	(172,092)
Net income	--	--	--	1,414,797	1,414,797
Balance, December 31, 2000	3,912,502	39,125	612,571	5,060,959	5,712,655
Issuance of common stock	1,000	10	1,990	--	2,000
Purchase of common stock	(119,275)	(1,193)	(219,271)	--	(220,464)
Net income	--	--	--	41,818	41,818
Balance, December 31, 2001	3,794,227	$ 37,942	$ 395,290	$ 5,102,777	$ 5,536,009

The accompanying notes are an integral part of these consolidated financial statements.

GEORESOURCES, INC., AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999

	2001	2000	1999
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 41,818	$ 1,414,797	$ 481,552
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and valuation allowance	744,742	674,020	635,797
Deferred income taxes	60,000	118,000	26,000
Other	34,107	2,262	2,192
Changes in assets and liabilities:			
Decrease (increase) in:			
Trade receivables	296,814	67,980	(467,021)
Inventories	51,647	48,524	106,500
Prepaid expenses and other	(32,496)	1,704	13,424
Increase (decrease) in:			
Accounts payable	40,827	(122,325)	217,537
Income taxes payable	(75,000)	75,000	--
Accrued expenses	29,953	24,922	68,539
Cash provided by operating activities	1,192,412	2,304,884	1,084,520
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(1,844,360)	(963,429)	(484,095)
Proceeds from sale of property and equipment	--	--	9,450
Collection of mortgage loans receivable	103,321	--	--
Cash used in investing activities	(1,741,039)	(963,429)	(474,645)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	775,000	--	160,000
Principal payments on long-term debt	(114,772)	(1,285,008)	(315,996)
Proceeds from issuance of common stock	--	7,475	--
Cost to purchase common stock	(220,464)	(172,092)	(71,191)
Debt issue costs	(15,000)	--	--
Cash provided by (used in) financing activities	424,764	(1,449,625)	(227,187)
INCREASE (DECREASE) IN CASH AND EQUIVALENTS	(123,863)	(108,170)	382,688
CASH AND EQUIVALENTS, beginning of year	315,191	423,361	40,673
CASH AND EQUIVALENTS, end of year	$ 191,328	$ 315,191	$ 423,361

The accompanying notes are an integral part of these consolidated financial statements.

GEORESOURCES, INC., AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)
YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999

	2001	2000	1999
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Cash paid (received) for:			
Interest	$ 45,365	$ 147,977	$ 165,435
Income taxes	73,400	949	(10,752)

NONCASH INVESTING AND FINANCING ACTIVITIES

During 2001, the Company issued 1,000 shares of common stock valued at $2,000 as partial payment of damage compensation on a gas property.

The accompanying notes are an integral part of these consolidated financial statements.

GEORESOURCES, INC., AND SUBSIDIARY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. SIGNIFICANT ACCOUNTING POLICIES:

Nature of Operations and Principles of Consolidation
The accompanying consolidated financial statements include the accounts of GeoResources, Inc., and its 84% owned subsidiary, Belmont Natural Resource Company, Inc. ("BNRC"). All material intercompany transactions and balances between the entities have been eliminated. The minority interest in BNRC at December 31, 2001 and 2000 is zero.

GeoResources, Inc. (the "Company") is primarily involved in oil and gas exploration, development and production in North Dakota and Montana and the mining of leonardite and manufacturing of leonardite products in North Dakota to be sold to customers located primarily in the Gulf of Mexico coastal areas. BNRC was incorporated in 1991 to exploit natural gas opportunities in the Pacific Northwest. All properties of the Company and BNRC are located in the United States.

During the third quarter of 2001, the Company purchased a used drilling rig. The rig was reconditioned by the Company and commenced drilling operations in January 2002. Also in January 2002, a newly formed subsidiary, Western Star Drilling Company ("WSDC"), was incorporated. In exchange for 100% of WSDC's outstanding common stock, the Company transferred the rig and all related equipment to WSDC and expects to transfer associated debt. WSDC intends to provide contract oil and gas drilling services to the Company and other operators in the Williston Basin area of North Dakota.

Reclassifications
Certain accounts in the prior-year financial statements have been reclassified for comparative purposes to conform with the presentation in the current-year financial statements.

Use of Estimates
The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates used in preparing these financial statements include the unaudited quantity of oil and gas reserves which directly affects the computation of depletion of oil and gas properties. It is at least reasonably possible that the estimates used will change within the next year.

Cash Equivalents
For purposes of the statements of cash flows, the Company considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. The Company periodically maintains cash balances in financial institutions in excess of FDIC limits. The Company evaluates the credit worthiness of these financial institutions in determining the risk associated with these deposits.

Inventories
Inventories are stated at the lower of cost (first-in, first-out method) or market.

A. SIGNIFICANT ACCOUNTING POLICIES (Continued):

Oil and Gas Properties

The Company utilizes the full cost method of accounting for oil and gas properties. Accordingly, all costs associated with the acquisition, exploration and development of oil and gas reserves (including costs of abandoned leaseholds, delay lease rentals, dry hole costs, geological and geophysical costs, certain internal costs associated directly with acquisition, exploration and development activities, and site restoration and environmental exit costs) are capitalized.

All capitalized costs of oil and gas properties, including the estimated future costs to develop proved reserves, are amortized on the unit-of-production method using estimates of proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. The Company's oil and gas depreciation, depletion and amortization rate per equivalent barrel of oil produced was $4.07, $3.31, and $2.99 for 2001, 2000, and 1999, respectively.

In addition, the capitalized costs are subject to a "ceiling test" which basically limits such costs to the aggregate of the "estimated present value," discounted at a 10-percent interest rate, of future net revenues from proved reserves, based on current economic and operating conditions, plus the lower of cost or fair market value of unproved properties. As a result of this ceiling test, the Company had no write-downs of its oil and gas properties during 2001, 2000 or 1999.

Gains or losses are not recognized upon the sale or other disposition of oil and gas properties, except in extraordinary transactions.

Costs not being amortized at December 31, 2001, consist of the unevaluated, unimpaired cost of undeveloped oil and gas properties that were acquired during the following years:

2001	$ 122,730
2000	49,554
1999	5,205
1998	16,110
1997 and prior	45,465
Total	$ 239,064

It is expected that evaluation of the above properties will occur primarily over the next three years.

Other Property and Equipment

Depreciation of other property and equipment is computed principally on the straight-line method over the following estimated useful lives:

Buildings	10-25 years
Machinery and equipment	3-10 years

A. SIGNIFICANT ACCOUNTING POLICIES (Continued):

Impairment of Long-Lived Assets
Potential impairment of long-lived assets (other than oil and gas properties) is reviewed whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. Impairment is recognized when the estimated future net cash flows (undiscounted and without interest charges) from the asset are less than the carrying amount of the asset. No impairment losses have been recognized on long-lived assets for the years ended December 31, 2001, 2000, and 1999.

Operating Costs and Expenses
Oil and gas production costs and the cost of leonardite sold exclude a provision for depreciation and depletion. Depreciation and depletion expense is shown in the aggregate in the accompanying statements of operations.

Income Taxes
Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes on temporary differences between the amount of taxable income and pretax financial income and between the tax bases of assets and liabilities and their reported amounts in the financial statements. Deferred tax assets and liabilities are included in the financial statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled. A valuation allowance is provided for deferred tax assets not expected to be realized.

Earnings Per Share of Common Stock
Basic earnings per share is determined using net income divided by the weighted average shares outstanding during the period. Diluted earnings per share is computed by dividing net income by the weighted average shares outstanding, assuming all dilutive potential common shares were issued. The effect of outstanding stock options was antidilutive in 2001, 2000 and 1999.

Recently Issued Accounting Pronouncements
In June 2001, the FASB issued Statement No. 141 (FAS 141) titled "Business Combinations". FAS 141 addresses financial accounting and reporting and for business combinations and supercedes previously issued authoritative literature on the topic, including APB 16. FAS 141 requires all business combinations after June 30, 2001 be accounted for under the purchase method of accounting. Implementation of FAS 141 is not expected to have an impact on the Company's financial statements.

In June 2001, the FASB issued Statement No. 142 (FAS 142) titled "Goodwill and Other Intangibles". Effective January 1, 2002, FAS 142 eliminates the amortization of goodwill and certain other intangible assets. These assets are now to be reviewed at least annually and assessed for impairment. Implementation of FAS 142 is not expected to have an impact on the Company's financial statements.

A. SIGNIFICANT ACCOUNTING POLICIES (Continued):

Recently Issued Accounting Pronouncements (Continued)

In June 2001, the FASB issued Statement No. 143 (FAS 143) titled "Accounting for Asset Retirement Obligations". Effective for fiscal years beginning after June 15, 2002, FAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The liability is to be discounted and accretion expense recognized using the credit-adjusted-risk-free interest rate in effect when the liability was initially recognized. Upon initial application of the statement, an entity is to 1)recognize a liability for any existing asset retirement obligations adjusted for the cumulative accretion to the date of adoption of the statement and 2)recognize an asset for retirement costs capitalized as an increase to the carry amount of the associated long-lived asset adjusted for the accumulated depreciation on that capitalized cost to the date of adoption of the statement. The Company is currently assessing the impact adopting FAS 143 will have on the Company's financial position and operations.

In August 2001, the FASB issued Statement No. 144 (FAS 144) titled "Accounting for the Impairment or Disposal of Long-Lived Assets". Effective for financial statements issued for fiscal years beginning after December 15, 2001, FAS 144 conforms the accounting for long-lived assets to be disposed of by sale to the model outlined in FAS No. 121" Accounting for the Impairment of Long-Lived Assets and for Long Lived Assets to be Disposed Of" and resolves certain implementation issues resulting from FAS 121. Implementation of FAS 144 is not expected to have a material impact on the Company's financial statements.

B. INDUSTRY SEGMENTS AND MAJOR CUSTOMER:

Segment Information

The Company assesses performance and allocates resources based upon its products and the nature of its production processes, which consist principally of a) oil and gas exploration, development and production and b) the mining and processing of leonardite. There are no sales or other transactions between these two operating segments and all operations are conducted within the United States. As discussed in Note A, as of December 31, 2001, the Company had made capital expenditures in the start-up of an oil and gas drilling business segment. There was no revenue or operating income or loss associated with this segment during 2001. Certain corporate costs, assets and capital expenditures that are considered to benefit the entire organization are not allocated to the Company's operating segments. Interest income, interest expense and income taxes are also not allocated to operating segments. There are no significant accounting differences between internal segment reporting and consolidated external reporting. Presented below is information concerning the Company's operating segments for the years ended December 31, 2001, 2000 and 1999:

	2001	2000	1999
Revenue:			
Oil and gas	$ 3,064,135	$ 4,436,278	$ 2,688,642
Leonardite	913,568	675,928	651,847
	$ 3,977,703	$ 5,112,206	$ 3,340,489
Operating income (loss):			
Oil and gas	$ 589,582	$ 2,224,724	$ 955,066
Leonardite	(44,276)	(117,445)	(35,538)
General corporate activities	(464,317)	(402,824)	(299,422)
	$ 80,989	$ 1,704,455	$ 620,106
Depreciation and depletion:			
Oil and gas	$ 618,394	$ 552,294	$ 519,407
Leonardite	104,562	102,856	100,590
General corporate activities	21,786	18,870	15,800
	$ 744,742	$ 674,020	$ 635,797
Identifiable assets, net:			
Oil and gas	$ 5,539,560	$ 5,333,322	$ 4,894,495
Leonardite	976,107	1,195,744	1,417,100
Drilling	968,064	--	--
General corporate activities	717,988	921,220	1,017,245
	$ 8,201,719	$ 7,450,286	$ 7,328,840
Capital expenditures incurred:			
Oil and gas	$ 1,066,050	$ 959,737	$ 544,049
Leonardite	2,500	35,888	--
Drilling	968,064	--	--
General corporate activities	23,317	29,482	5,086
	$ 2,059,931	$ 1,025,107	$ 549,135

B. INDUSTRY SEGMENTS AND MAJOR CUSTOMER (Continued):

Major Customer
Sales to a major oil and gas customer were 55%, 62% and 60% of total revenue for the years ended December 31, 2001, 2000 and 1999, respectively. Accounts receivable from this major customer were 31% and 40% of total accounts receivable at December 31, 2001 and 2000, respectively.

C. TRADE RECEIVABLES AND INVENTORIES:

Trade receivables at December 31, 2001 and 2000 are comprised of the following:

	2001	2000
Oil and gas purchasers	$ 398,216	$ 627,446
Leonardite customers	239,559	307,143
	637,775	934,589
Less allowance for doubtful accounts	(11,416)	(11,416)
	$ 626,359	$ 923,173

As of December 31, 2001 and 2000, inventories by major classes are comprised of the following:

	2001	2000
Crude oil	$ 67,634	$ 60,715
Leonardite inventories:		
Finished products	66,124	63,780
Raw materials	24,246	57,158
Materials and supplies	38,854	66,852
Total leonardite inventories	129,224	187,790
	$ 196,858	$ 248,505

D. MORTGAGE LOANS RECEIVABLE, RELATED PARTY

Mortgage loans receivable, related party represent mortgage loans on the residence of a former officer/shareholder of BNRC purchased from a third party in November 1993. The mortgage loans were repaid in full in 2001. The Company's interest income from these loans was $4,986, $8,100 and $8,100 for the years ended December 31, 2001, 2000 and 1999.

E. LONG-TERM DEBT:

Long-term debt at December 31, 2001 and 2000 consists of the following loans and a revolving line of credit (RLOC) which are all with one bank:

	2001	2000
The 1997 Oil & Gas Loan, prime plus .75% (5.5% total rate at December 31, 2001), due in monthly installments of $10,417 plus interest through January 2005, collateralized by oil and gas properties	$ 385,228	$ 500,000
The 2001 Oil & Gas RLOC, $3,000,000 revolving line of credit expires January 5, 2004, interest only payable at prime through January 2004 (4.75% rate at December 31, 2001), principal and interest payable thereafter through January 2008, collateralized by oil and gas properties	775,000	--
Total long-term debt	1,160,228	500,000
Less current maturities	(125,000)	(175,000)
Long-term debt, less current maturities	$ 1,035,228	$ 325,000

Aggregate maturities required on long-term debt at December 31, 2000, are as follows:

Year Ending December 31:	
2002	$ 125,000
2003	125,000
2004	318,750
2005	203,978
2006	193,750
Thereafter	193,750
	$ 1,160,228

The Company's borrowing base for debt secured by oil and gas properties is limited by the net present value of future oil and gas production of the properties as determined annually by the bank.

E. LONG-TERM DEBT (Continued):

The Company's long-term debt was obtained pursuant to financing agreements which include the following covenants: Maintain a current ratio of not less than 1.25 to 1 exclusive of current maturities of long-term debt; maintain debt to tangible net worth of not more than 1.5 to 1; not encumber certain of its assets; restrict borrowings from, and credit extensions to, other parties; restrict reorganization or mergers in which the Company is not the surviving corporation; and not pay cash dividends without the bank's consent. The Company was not in compliance with the current ratio requirement at December 31, 2001.

F. INCOME TAXES:

The components of income tax expense for the years ended December 31, 2001, 2000 and 1999, are as follows:

	2001	2000	1999
Current tax benefit (expense)	$ 23,000	$ (75,000)	$ --
Deferred tax benefit (expense)	85,000	(282,000)	(168,000)
Decrease (increase) in deferred tax assets valuation allowance	(145,000)	164,000	142,000
Income tax (expense)	$ (37,000)	$ (193,000)	$ (26,000)

During 2001, the Company recorded a deferred tax benefit of $85,000. This resulted primarily from a net operating loss generated for which there are no currently refundable federal taxes. A receivable for state income taxes of $23,000 has been recorded for the carryback of the 2001 net operating loss. The Company also increased the deferred tax asset valuation allowance by $145,000 based upon the projection of utilizing less statutory depletion carryforwards in the future.

During 2000 and 1999, the Company recorded deferred tax expense of $282,000 and $168,000, respectively. This related primarily to net income that was not currently taxable due to the utilization of net operating loss carryforwards and the deduction of intangible drilling costs for tax purposes. The Company also decreased the deferred tax asset valuation allowance by $164,000 and $142,000 during 2000 and 1999, respectively, primarily based upon the current utilization of net operating loss carryforwards and the projection of utilizing additional statutory depletion carryforwards in the future.

F. INCOME TAXES (Continued):

The tax effects of significant temporary differences and carryforwards which give rise to the Company's deferred tax assets and liabilities at December 31, 2001 and 2000, are as follows:

	2001	2000
Deferred Tax Assets:		
Net operating loss carryforward	$ 86,000	$ --
Statutory depletion carryforward	1,487,000	1,277,000
Other	49,000	68,000
	1,622,000	1,345,000
Valuation Allowance:		
Beginning of year	(676,000)	(840,000)
(Increase) decrease	(145,000)	164,000
End of year	(821,000)	(676,000)
Deferred Tax Liabilities:		
Accumulated depreciation and depletion	(1,145,000)	(953,000)
Net Deferred Tax Liability, long-term	$ (344,000)	$ (284,000)

The provision for income taxes does not bear a normal relationship to pre-tax earnings. A reconciliation of the U.S. federal income tax rate with the actual effective rate for the years ended December 31, 2001, 2000 and 1999 is as follows:

	2001	2000	1999
Income tax expense (benefit) at statutory rate	35%	35%	35%
Change in valuation allowance	184	(10)	(28)
Net operating loss	(137)	(24)	--
State income taxes and other	(35)	11	(2)
	47%	12%	5%

For income tax purposes, the Company has a statutory depletion carryover of approximately $4,933,000 that, subject to certain limitations, may be utilized to reduce future taxable income. This carryforward does not expire. The Company also has a federal net operating loss carryforward of approximately $370,000, which if not utilized, will expire in 2021.

G. STOCK OPTION AND PROFIT-SHARING PLANS:

Stock Option Plan

In 1993, the Company adopted the 1993 Incentive Stock Option Plan, whereby 300,000 shares of the Company's common stock are reserved for options which may be granted pursuant to the terms of the plan. Under the terms of the plan, the option price may not be less than 100% of the fair market value of the Company's common stock on the date of grant, and if the optionee owns more than 10% of the voting stock, the option price per share shall not be less than 110% of the fair market value.

Information with respect to the stock option plan's activity is as follows:

	Shares Available for Options	Shares Subject to Outstanding Options
December 31, 1998	17,500	265,000
Granted	--	--
Expired	--	--
Exercised	--	--
December 31, 1999	17,500	265,000
Granted	--	--
Expired	80,500	(80,500)
Exercised	--	(6,500)
December 31, 2000 and 2001	98,000	178,000

Information with respect to the options outstanding and exercisable at December 31, 2001, is as follows:

Number of shares	Exercise Price	Expiration Date
87,500	2.37	May 2007
90,500	2.31	December 2007
178,000		

The average exercise price is $2.34 for options outstanding and exercisable at December 31, 2001.

G. STOCK OPTION AND PROFIT-SHARING PLANS (Continued):

Profit-sharing Plan

The Company has a 401(k) profit sharing plan that covers all employees with one year of service who elect to enter the plan. Effective July 1, 1997, the Company amended the plan to provide for employee contributions. Employees may elect to contribute up to 15% of their compensation to a maximum of $10,000. The Company contributes an amount equal to each employee's contribution up to a maximum of 5% of the employee's compensation. The Company may also make additional discretionary contributions to the plan. The Company's total contributions to the plan, matching and discretionary, for the years ended December 31, 2001, 2000 and 1999 were $24,614, $36,474 and $37,312, respectively.

H. CONTINGENCIES:

All of the Company's operations are generally subject to federal, state or local environmental regulations. The Company's oil and gas business segment is affected particularly by those environmental regulations concerned with the disposal of produced oilfield brines and other wastes. The Company's leonardite mining and processing segment is subject to numerous state and federal environmental regulations, particularly those concerned with air quality at the Company's processing plant, and surface mining permit and reclamation regulations. The amount of future environmental compliance costs cannot be determined at this time.

I. OFFICE FACILITIES:

In 1991, the Company purchased an office building, one-half of which it occupies. The building is included in other property and equipment in the accompanying balance sheets and consists of the following at December 31, 2001 and 2000:

	2001	2000
Building and improvements	$ 163,834	$ 163,834
Accumulated depreciation	(88,327)	(80,136)
	$ 75,507	$ 83,698

The Company leases the remainder of the building to unaffiliated businesses under cancelable lease agreements. During 2001, 2000 and 1999, the Company received $20,675, $20,500, and $21,300, respectively, in rental income from the building which is included in other income in the accompanying statements of operations.

J. FINANCIAL INSTRUMENTS:

The carrying amounts reflected in the consolidated balance sheets for cash and equivalents, short-term receivables and short-term payables approximate their fair value due to the short maturity of the instruments. The carrying value of mortgage loans receivable approximates fair value based on discounted future cash flows. The carry value of long-term debt approximates fair value based on the variable nature of the interest rates.

During 2001 and 2000, the Company did not engage in any hedging activities. In 1999, the Company used derivative financial instruments to manage its crude oil commodity price risk. They were not used for trading purposes. The Company hedged 5% to 35% of its crude oil sales using various financial instruments including "put" and "call" options and, to a lesser extent, actual future contracts on crude oil and energy products that trade on the New York Mercantile Exchange ("NYMEX"). The variation in types of instruments employed results from a strategy designed to provide primarily short to intermediate term protection (less than one year) from oil price declines that would occur in a wide range. Generally, the Company does not hedge against narrow-range oil price movements. Since these financial instruments correlate to crude oil and energy products price movements, gains or losses resulting from market changes will be offset by losses or gains on the Company's crude oil sales. Included in oil and gas sales are losses from hedging activities totaling $none, $none, and $108,199 for the years ended December 31, 2001, 2000 and 1999, respectively. At December 31, 2001 and 2000, the Company had no derivative financial instruments.

K. FOURTH QUARTER ADJUSTMENTS:

During the fourth quarter of 2001, depletion expense increased $212,598 over the amount reported at September 30, 2001. This was due to the fourth quarter decline in oil prices that reduced the Company's estimated quantity of proved oil and gas reserves as of December 31, 2001.

L. OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES:

Net capitalized costs related to the Company's oil and gas producing activities are summarized as follows as of December 31, 2001, 2000 and 1999:

	2001	2000	1999
Proved properties	$ 21,594,355	$ 20,647,855	$ 19,664,222
Unproved properties	239,067	119,517	143,413
Total	21,833,422	20,767,372	19,807,635
Less accumulated depreciation, depletion, amortization and impairment	(16,771,414)	(16,153,020)	(15,600,726)
Net capitalized costs	$ 5,062,008	$ 4,614,352	$ 4,206,909

L. OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES (Continued):

Costs incurred in oil and gas property acquisition, exploration and development activities, including capital expenditures are summarized as follows for the years ended December 31, 2001, 2000 and 1999:

	2001	2000	1999
Property acquisition costs:			
Proved	$ 31,138	$ 24,908	$ 20,259
Unproved	135,148	75,209	21,159
Exploration costs	82,976	81,775	57,310
Development costs	816,788	777,845	445,321
	$ 1,066,050	$ 959,737	$ 544,049

The Company's results of operations from oil and gas producing activities (excluding corporate overhead and financing costs) are presented below for the years ended December 31, 2001, 2000 and 1999:

	2001	2000	1999
Oil and gas sales	$ 3,064,135	$ 4,436,278	$ 2,688,642
Production costs	(1,856,159)	(1,659,260)	(1,214,169)
Depletion, depreciation and amortization	(618,394)	(552,294)	(519,407)
	589,582	2,224,724	955,066
Imputed income tax provision	--	(560,000)	(104,000)
	$ 589,582	$ 1,664,724	$ 851,066

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

The reserve information presented below is based upon reports prepared by the independent petroleum engineering firm of Broschat Engineering and Management Services. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of mature producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under economic and operating conditions existing as of the end of each respective year. The year-end selling price of oil and gas is one of the primary factors affecting the determination of proved reserve quantities which fluctuate directly with that price. The selling price of oil was significantly lower at December 31, 2001, than at December 31, 2000 or 1999.

L. OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES (Continued):

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited) (Continued)
Presented below is a summary of the changes in estimated proved reserves of the Company, all of which are located in the United States, for the years ended December 31, 2001, 2000 and 1999:

	2001		2000		1999	
	Oil (bbl)	Gas (mcf)	Oil (bbl)	Gas (mcf)	Oil (bbl)	Gas (mcf)
Proved reserves, beginning of year	2,487,000	545,000	2,566,000	257,000	1,286,000	234,000
Purchases of reserves-in-place	--	--	9,000	135,000	--	--
Sales of reserves -in-place	(1,000)	(72,000)	--	--	--	--
Extensions and discoveries	--	--	12,000	115,000	--	--
Improved recovery	--	--	--	--	44,000	--
Revisions of previous estimates	(238,000)	(112,000)	65,000	48,000	1,418,000	31,000
Production	(150,000)	(11,000)	(165,000)	(10,000)	(182,000)	(8,000)
Proved reserves, end of year	2,098,000	350,000	2,487,000	545,000	2,566,000	257,000

Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Proved developed reserves of the Company are presented below as of December 31:

	Oil (bbl)	Gas (mcf)
2001	1,330,000	350,000
2000	1,680,000	545,000
1999	1,759,000	257,000

L. OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES (Continued):

Standardized Measure of Proved Oil and Gas Reserves (Unaudited)
Statement of Financial Accounting Standards No. 69 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines which are briefly discussed below. Future cash inflows and future production and development costs are determined by applying year-end selling prices and year-end production and development costs to the estimated quantities of oil and gas to be produced. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates are the basis for the valuation process. Estimated future income taxes are computed using current statutory income tax rates including consideration for estimated future statutory depletion, depletion carryforwards, net operating loss carryforwards, and investment tax credit carryforwards. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect the Company's expectations of actual revenues or future net cash flows to be derived from those reserves nor their present worth.

Presented below is the standardized measure of discounted future net cash flows as of December 31, 2001, 2000 and 1999. As shown, the future cash inflows as of December 31, 2001, were significantly lower than at December 31, 2000 or 1999. This is primarily due to the low oil price in effect on December 31, 2001.

	2001	2000	1999
Future cash inflows	$ 29,635,000	$ 62,757,000	$ 55,686,000
Future production costs	(13,963,000)	(22,865,000)	(19,665,000)
Future development costs	(3,958,000)	(4,037,000)	(3,738,000)
Future income tax expense	(2,114,000)	(10,220,000)	(8,449,000)
Future net cash flows	9,600,000	25,635,000	23,834,000
Less effect of a 10% discount factor	(4,120,000)	(10,613,000)	(10,106,000)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 5,480,000	$ 15,022,000	$ 13,728,000

L. OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES (Continued):

Standardized Measure of Proved Oil and Gas Reserves (Unaudited) (Continued)

The principal sources of change in the standardized measure of discounted future net cash flows are as follows for the years ended December 31, 2001, 2000 and 1999:

	2001	2000	1999
Standardized measure, beginning of year	$ 15,022,000	$ 13,728,000	$ 2,836,000
Sales of oil and gas produced, net of production costs	(1,208,000)	(2,777,000)	(1,474,000)
Net changes in prices and production costs	(12,192,000)	2,898,000	7,219,000
Purchases of reserves-in-place	--	283,000	--
Sales of reserves-in-place	(54,000)	--	--
Extensions, discoveries and other additions, less related costs	--	286,000	351,000
Revisions of previous quantity estimates and other	(1,240,000)	389,000	11,321,000
Development costs incurred during the year and changes in estimated future development costs	45,000	(175,000)	(2,006,000)
Accretion of discount	480,000	1,428,000	200,000
Net change in income taxes	4,627,000	(1,038,000)	(4,719,000)
Standardized measure, end of year	$ 5,480,000	$ 15,022,000	$ 13,728,000

OFFICERS & DIRECTORS

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Director & President
Williston, North Dakota

Jeffrey B. Jennings
VP, Land & Finance
Williston, North Dakota

Thomas F. Neubauer
VP, Leonardite Operations
Williston, North Dakota

Cathy Kruse
Director & Secretary
Williston, North Dakota

Connie R. Hval
Treasurer
Williston, North Dakota

H. Dennis Hoffelt
Director
Williston, North Dakota

Paul A. Krile
Director
President & Owner
Ranco Fertiservice
Sioux Rapids, Iowa

Duane Ashley
Director
Senior Salesman
Weatherford Enterra, Inc.
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Jones & Keller
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AUDITORS

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TRANSFER AGENT

For information regarding change of address or other information regarding your stockholder account, please contact our transfer agent directly:
Wells Fargo Bank Minnesota, N.A.
Shareholder Services
P.O. Box 64854
St. Paul, Minnesota 55164-0854
1-800-468-9716

STOCK TRADED

Our Common Stock trades on the Nasdaq SmallCap Market tier of the Nasdaq Stock Market under the symbol GEOI.

SECURITY MARKET MAKERS

The following investment securities firms made a market in our Common Stock during 2001:

D.A. Davidson & Co., Inc., Great Falls, MT
Herzog, Heinz, Geduld, Inc., Jersey City, NJ
Island System Corporation, New York, NY
Knight Securities L.P., New York, NY
Miller Johnson Steichen Kinnard, Minneapolis, MN
Morgan, Keegan, Inc., Birmingham, AL
Spear, Leeds & Kellogg, Jersey City, NY

FORWARD LOOKING INFORMATION

Information herein contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, which can be identified by words such as "may," "expect," "anticipate," "estimate," or "continue," or comparable words. In addition, all statements other than statements of historical facts that address activities that the Company expects or anticipates will or may occur in the future are forward-looking statements. Readers are encouraged to read the SEC reports of the Company, particularly its Form 10-KSB for the Fiscal Year Ended December 31, 2001, for meaningful cautionary language disclosure.

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